BIOMASS STRATEGIC VALUE ANALYSIS

**IN SUPPORT OF THE
2005 INTEGRATED ENERGY POLICY REPORT**

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Abstract

California has one of the nation's biggest, most diverse, and widespread biomass resource supply systems. It has an existing generation capacity of about 1000 megawatt and the potential to increase this capacity in the years to come. Using the strategic value analysis or "least cost best fit" methodology, the current existing biomass capacities could more than double by 2017. The challenge facing the state will be how best to integrate and manage biomass energy resources, in tandem with other resources, while ensuring reliability of the state's electrical system. This paper presents the SVA as a tool to provide a logical approach to integrating more biomass energy generation into California's electricity system while simultaneously providing non-energy benefits, improving transmission reliability, and helping meet the RPS targets and the Energy Action Plan.

Acknowledgements

Table of Contents

Introduction

California has prevalent, diverse, and widespread biomass resources. These biomass resources include residues from agriculture and forestry, a portion of municipal solid wastes, and organic material in waste waters. The constructive use of these resources may be sufficient to support much greater use in electricity generation, fuels and chemicals, manufacture, and production of a wide variety of biobased products with all the associated benefits of both solving waste disposal and environmental problems.

Renewable resources currently provide approximately 11 percent of the state's electricity mix.[1] Biomass conversion accounted for more than 2% of that mix. California's Renewable Portfolio Standard (RPS), established in 2002 by Senate Bill 1078 (SB1078, Sher, Chapter 516, Statutes of 2002), requires that electricity providers procure at least one percent of their electricity supplies from renewable resources to achieve a 20 percent renewable mix by no later than 2017. The California Energy Commission, the California Public Utilities Commission and the California Power Authority more recently approved the Energy Action Plan (EAP), accelerating the 20 percent target date to 2010.[1] How best to achieve this target and capture its benefits remain to be a challenge and are open to public policy considerations and private investment decisions.

The PIER Renewables Program in the California Energy Commission (Energy Commission) is developing a "Least Cost-Best Fit" methodology to determine the best locations to construct renewable resources at the lowest cost to ratepayers. This methodology is referred to as the Strategic Value Analysis (SVA). SVA provides the vision for integrating future renewables into the California grid. Principal components of the vision include:

> Assess renewable technology resource potential to meet RPS goals.
> Identify key focus areas for each renewable technology.
> Evaluate economics and timeframe for development for maximum public benefits.
> Evaluate points of interconnection for high strategic value to the grid.
> Consider solutions with significant environmental, economic and other non-energy benefits to the state.
> Provide solutions that can defer transmission upgrades and help prioritize transmission needs.
> Prioritize renewable implementation and transmission infrastructure needs.

This staff paper describes the approach and findings of the biomass SVA to assist in meeting the California renewable penetration targets while capturing social, economic and environmental benefits and improving transmission reliability.

Methodology

In 2002, The PIER Renewables Program initiated a project that has become known as the strategic value analysis (SVA). The main goal of SVA is improvement of the reliability and quality of California's electrical system by identification of where renewable electricity system can best be located to help alleviate transmission and distribution capacity and congestion problems. This project will use a combination of power flow models and geographical information system (GIS) tools that will identify the ability of renewable generation systems to address electricity system problems and identify optimal locations for renewable generation systems. It is essentially a "least cost-best fit" methodology for determining the best locations to construct renewable resources at the lowest cost to ratepayers.

SVA's goal is to guide the PIER Renewables Program's efforts to fund renewable electricity generation RD&D. Coincidentally, the California RPS was enacted into law and SVA was of great assistance in the RPS implementation. The SVA is a tool to provide a logical approach to integrating more renewable energy generation into California's electricity system while simultaneously providing non-energy benefit and improving transmission reliability. It is a multi-phased effort combining renewable resource assessment, state-of-the-art power flow analyses, filtering criteria to identify development priorities and sites within a GIS platform, and economic analysis of MW solutions. Results should also address the magnitude and timeframe for transmission and distribution upgrades to the state's electrical system to enable the addition of new renewable generation.

The general approach to SVA appears in Figure 1. The principal components of the biomass SVA include:

> Update biomass resource assessment. Estimate gross and technical potential of biomass resources.
> Review and characterize biomass energy development in California, including: identification of existing biomass facilities, biomass usage, performance and cost trends, and barriers to biomass energy development.
> Evaluate the economic potential of biomass resources and use GIS analysis.
> Use power flow simulations and GIS scenario analysis to identify "hot spots" and provide solutions that defer transmission upgrades and help prioritize transmission needs.
> Evaluate economics of biomass energy conversion technologies.
> Evaluate MW solutions that will meet RPS targets by 2010 and 2017 with significant economic, environmental, and other public benefits.

Figure 1. SVA Approach and Inputs to Support Energy Policy
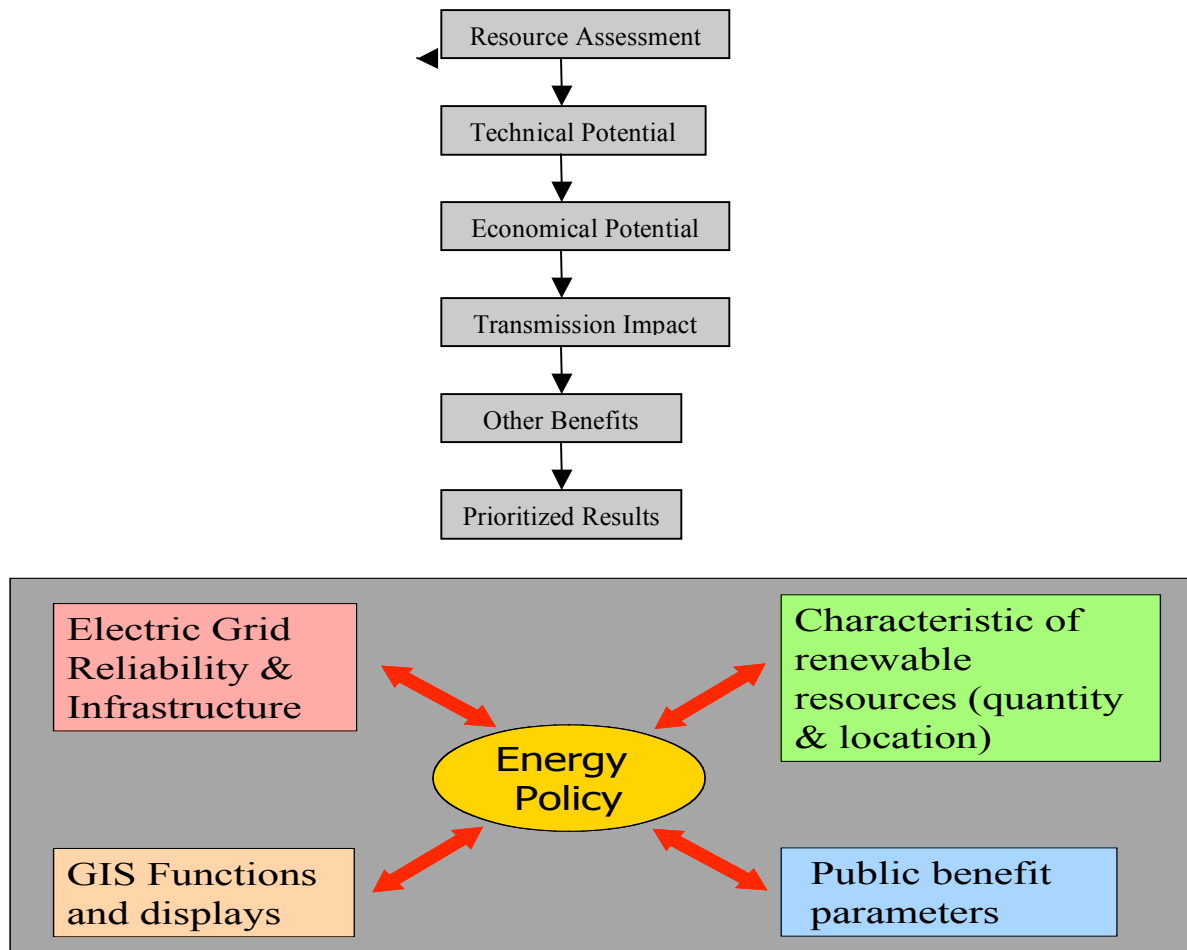
The biomass SVA team includes staff from the California Energy Commission, California Biomass Collaborative, California Department of Forestry and Fire Protection, Davis Power Consultants, Power World, Anthony Engineering and McNeil Technologies.

The detail methodology of the SVA components is described below:

Resource Assessment

An assessment of biomass resources in California was conducted by California Biomass Collaborative[2] for the purpose of evaluating the potential quantities that can be used for energy, fuels, and other products. A staff paper about this resource assessment was written and presented on May 9, 2005, at the Intrastate IEPR Workshop[2]. The forestry resource assessment was conducted by

Fire and Resource Assessment Program, California Department of Forestry and Fire Protection[3].

Gross and technically available resources were quantified and compiled into statewide and county-level inventories. Using assumptions regarding current and future conversion paths, possible contributions from biomass toward meeting the renewable electricity goals under the state's Renewable Energy Portfolio (RPS) for 2005, 2010 and 2017 were also developed. The biomass production data can be used to estimate development potentials for other purposes, but only estimates for electricity capacity and energy are included in this report.

Resources considered for this analysis include biomass from agriculture, forestry, municipal wastes, and dedicated biomass crops in the following categories:

Agricultural residue biomass.
- o Orchard and vineyard crops.
- o Field and seed crops.
- o Vegetable crops.
- o Food processing residues.
- o Animal manures.

Forest residues and thinnings.
- o Forest thinnings and slash.
- o Chaparral.
- o Mill residues.

Municipal wastes.
- o Biomass fraction of municipal solid waste (MSW).
  - Paper and cardboard.
  - Food wastes.
  - Green wastes including leaves, grass, prunings, stumps.
  - Other organics.
- o Biosolids from waste water treatment operations.
- o Landfill gas.
- o Sewage digester gas.

Dedicated biomass crops.

Current gross quantities in bone dry tons per year (BDT/y)[4] were derived from crop production, timber harvest, waste disposal, and other data. Although dedicated biomass crops are not currently grown to any large extent in the state, gross approximations of future development were made for purposes of gauging potential impacts. For reporting purposes, all results are aggregated at the state and county levels.

To evaluate the technical potentials, filters such as agronomic and ecological requirements, terrain limitations, inefficiencies in biomass collection and handling, and other constraints were considered. Not all of the gross biomass

resource identified is available for utilization. Technical resource potential is therefore calculated based on these physical system constraints. For example, for forest biomass the areas excluded from the gross potential as filters include the following:

- National forest lands with slopes greater than 35%;
- Private and other public forest lands with slopes greater than 30%;
- Stream management zones (200 ft. on either side of streams);
- Coastal protection zones (indicated by zone lines);
- Coastal sage scrub habitats, and
- Reserves.[5]

The technical potentials data are then used as the basis for more comprehensive and site specific economic analysis using power flow and GIS platform.

To both address the contribution to electricity generation from biomass and to provide information needed for the economic assessments, projections from the base 2003 year inventory were made for the years 2005, 2007, 2010, and 2017. Gross and technical power generation potentials were computed from the resource estimates and assumptions regarding conversion technology, efficiency, capacity factor, and individual material properties such as heating value and biodegradability. Low-moisture materials such as wood and some field crop residues were assumed to be converted using thermal technologies, while high-moisture materials such as dairy cattle manures, green waste, and food waste were assumed to be converted through anaerobic digestion; moisture content: however, was not the only criterion used in assigning the conversion class. In many cases conversion efficiencies for thermal and biological systems were similar.

Landfill gas will remain an important resource for power generation through 2017 even if the state further reduces waste disposal. The large amount of waste already in place will continue to generate gas well into the future. Bioreactor landfills can increase landfill gas generation capacity from new waste disposal due to enhanced conditions for the microorganisms and faster gas production rates. Potential capacity increases from shifting to bioreactor landfills were also assessed.

Net thermal conversion efficiencies were assumed to remain constant through 2007 at an average of 20 percent (based on dry matter higher heating value) and then increase due to improvements in boiler operations or adoption of enhanced technologies such as integrated gasification combined cycles for new capacity additions. Average efficiency was increased to 25 percent in 2010 and to 30 percent in 2017. Overall efficiencies in combined heat and power operations were not incorporated into this analysis but economic factors will certainly influence such technology selection in the future, with potential ramifications for average net electrical generation efficiency.

Net biological conversion efficiencies were based the biodegradability of the biomass in anaerobic digestion or decomposition and the efficiency of the engine-generator set (genset) or other generator system fueled with the resulting biogas. Genset efficiency was assumed to be 30 percent for all landfill and digester gas applications. Bioconversion efficiencies were not escalated over time. For the assumptions employed, overall net bioconversion efficiencies ranged from 13 to 22 percent based upon the higher heating value of total solids.

Characterization of biomass energy development in California

A review and survey of biomass energy development in California were conducted to identify and characterize existing biomass facilities. These facilities include direct combustion technologies such as fluidized bed and stoker boiler, integrated biomass combined cycle (BIGCC) and anaerobic digestion technologies such as dairy waste to biogas, wastewater treatment to biogas, and landfill gas to energy. Biomass fuel utilization and competing uses were estimated for all energy conversion facilities. Performance and cost trends of these biomass conversion facilities were also identified, as were barriers to biomass energy development.

Economic potential of biomass resources

Based upon the technical potential prepared by California Biomass Collaborative and CDF, the economic potential of biomass was estimated. The economic potential is defined as BDT and MW generation based on the amount of biomass that could be collected, processed and transported within a 25-mile radius of each substation. Economic potential excludes, use of biomass fuels from existing facilities. Selected substations were assumed to be within the proximity of the biomass power generation system. For example, CDF located areas in California susceptible to forestry and shrub land wildfire threat. CDF calculated both the amount of forest biomass (within 25-mile radius of the substation) in BDT and the economic MW equivalent that could be harvested from these fire threat areas. Maps were created that show the fire threat areas with BDT/MW and transmission hot spots for power-flow analysis. For the highest fire threat areas, a minimum of 120,000 BDT was used as the cutoff point.

A similar procedure was used for other biomass resources from agriculture and municipal solid waste. Again, a 25-mile radius was assumed in estimation of the economic potential of these resources.

3.2 Power flow simulations and GIS scenario analysis

Power flow simulations and GIS analysis were conducted by DPC team and CDF. A GIS tool identified possible areas within California's transmission and

distribution system where adequacy or reliability problems (otherwise known as "hot spots") could emerge. It also provided solutions that deferred transmission upgrades and prioritized, transmission needs. Power flow analyses were used to identify the "hot spots" under summer peak conditions for 2005, 2007, 2010 and 2017.

DPC developed a metric called the Weighted Transmission Loading Relief Factor (WTLR) as a single indicator of the effectiveness of overload mitigation at each bus (substation). The WTLR represents the expected contingency megawatt overload reduction if 1 MW of new generation is injected at that bus. For example, a bus with a WTLR of 4 means that for every 1 MW of installed generation there will be a corresponding 4 MW reduction in the contingency overload. Since there are transmission overloads among transmission lines rated from 69 kV to 500 kV in different utility control areas, DPC developed a methodology that compares the transmission benefits of locating different power plants at different locations.

In basic terms, this methodology uses the number of violation occurrences, nominal voltage of the element and the average percent overload over all of the occurrences to calculate the WTLR for each element. If all the individual WTLRs are added together, the result is an Aggregated Megawatt Contingency Overload (AMWCO).

This methodology is an independent means of prioritizing locations for new power plants (conventional or renewable). The approach allows a comparison in the reduction of the AMWCO for generation sited at different WTLR locations. For example, assume a substation AMWCO is 10,000 MW and there are two possible projects that can reduce the AMWCO. One project provides power at 500 kV with a WTLR of 2 that reduces the AMWCO down to 9,500. The second project provides power at 115 kV with a WTLR of 4 that reduces the AMWCO to 9,000. The 115 kV site would be selected as the priority location due to its greater reduction in the AMWCO.

An AMWCO is a metric of the reliability of the transmission grid. It is not to be confused with an amount of generation or transmission needed for the system. Used in combination, the WTLR indicates the effectiveness of installing new generation at a bus, while the AMWCO indicates the overall improvement that the new generator has on the reliability of the entire system.

DPC developed a detailed state-wide transmission load flow and associated maps that highlighted the location of transmission congestion areas. These hot spot locations were transferred to an Excel spreadsheet and sent to CDF. CDF then prepared an overlay map that displayed the transmission hot spots and the

economic potential of biomass. This data was also put into an Excel spreadsheet.

The locations on the maps were then analyzed in the transmission load flow model to determine which biomass resources, provided transmission benefits to the system. If the biomass conversion technology improved transmission reliability and reduced transmission overloads, then it was considered for further analysis. If the installation of the renewable resource further decreased transmission reliability, then it was not considered for further analysis.

Since the biomass resource cannot be exactly located at the transmission hot spot, transmission upgrades or new transmission lines may need to be constructed. DPC estimated these potential transmission costs and Energy Commission staff used these costs to calculate the levelized cost of electricity (LCOE) with and without transmission costs discussed below.

Evaluate economics of biomass energy conversion technologies

Simple spreadsheet economic models were developed to estimate the cost of electricity for various biomass energy technologies based upon revenue requirements. This approach determines, the energy revenue ($/kWh) required to earn the desired rate of return. The analysis determines the energy price needed to yield the desired rate of return. The calculation considers return on investment, recovery of capital, and all expenses and taxes over the economic life of the project. Since this method specifies the rate of return to be earned, taxes are computed differently. Derivation of tax formulation and basic foundation of this model can be found on the California Biomass Collaborative website, http://biomass.ucdavis.edu/[2] and open calculator. The models generate an estimate of the levelized (or annual level) cost of electricity. They then calculate the constant and current dollar-levelized cost of electricity. Constant dollar analysis excludes the effects of inflation while current dollar or nominal dollar analysis includes the effect of inflation.

The assumptions used for the models using fluidized bed, stoker boiler, integrated biomass combined cycle (BIGCC), dairy waste to biogas, wastewater treatment to biogas, and landfill gas to energy are described below:

> The LCOE calculations assumed a project/owner developer perspective. An accelerated depreciation (MACRS – 5 year property) was assumed. Biomass fuel cost = $22/BDT for agricultural residues and urban wood and $40/BDT for forest fuels (thinnings and timber stand improvement) with wildfires threat. Zero fuel cost was assumed for dairy waste to biogas, wastewater treatment to biogas, and landfill gas to energy.
> Federal tax and state tax rates were assumed at 34% and 6.65%, respectively.

Financing assumed 2:1 or 67% debt ratio, 8.4% interest rate on debt, 16% cost of equity, and 20 years' economic life.

General inflation and escalation rates for O&M and other expenses were assumed at 2.8%.

Production tax credit (PTC) is available for biomass project, at least 5 years at $0.009/kWh[6].

In the calculation of LCOE, capacity payments were assumed to be at $166/kW-year. Capacity payments are provided under some contracts by utilities or generators that can guarantee their facilities will operate with high reliability during the year, especially during times of peak electricity demand.

The estimated capital and O&M cost, fuel cost, and capacity factors for each technology are shown below:

Figure 2. Capital Cost Breakdown Of Fluidized Bed Combustor[7]

Capital Cost of Fluidized Bed Combustor

Project & Process Contingency, 11%
Owners costs, 4%
Fuel Handling System, 7%
Boiler, 28%
General Facilities & Engineering Fee, 23%
Balance of Plant (Emission controls, etc), 12%
Baghouse & Cooling Tower, 4%
Steam Turbine & Auxiliaries, 9%
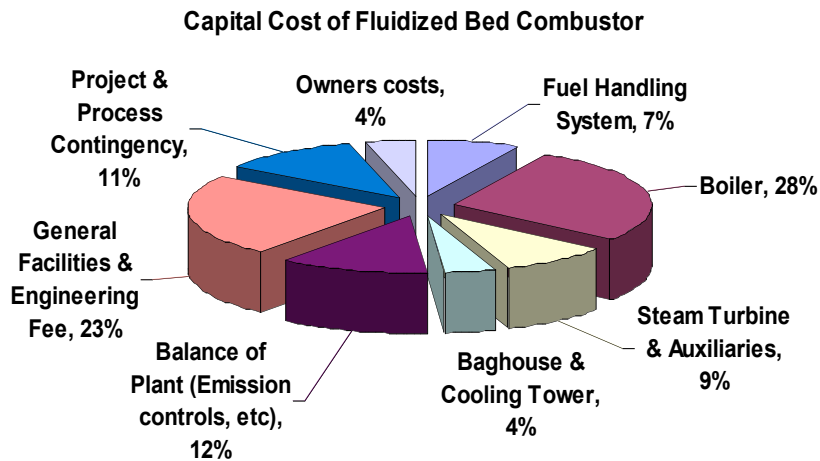
Table 1. Capital And O&M Costs (2004$), Capacity Factor, And Efficiency Of Fluidized Bed Combustor [8]

Technology	25 MW Fluidized Bed Combustor			
Year	2005	2007	2010	2017
Installed Capital Cost ($/kW)				
Fuel Handling System	207	200	178	163
Boiler	785	757	673	616
Steam Turbine & Auxiliaries	255	246	219	201
Baghouse & Cooling Tower	117	113	100	92
Balance of Plant (Emission controls, etc)	343	330	294	269
General Facilities & Engineering Fee	656	632	562	515
Project & Process Contingency	322	310	276	253
Owners costs	116	112	99	91
Total Capital Cost	**2,800**	**2,700**	**2,400**	**2,200**
Operation and Maintenance Cost ($/kW-yr)				
Fuel Cost ($/BDT)*	22.0	22.0	20.00	20.00
Labor Cost	80	78	78	76
Maintenance Cost	60	59	58	57
Insurance/Property Tax	56	55	54	53
Utilities	8	8	8	8
Ash Disposal -use negative value for sales	4	4	4	4
Management/Administration	8	8	8	8
Other Operating Expenses	16	16	16	15
Total Non-Fuel Expenses	**232**	**227**	**225**	**220**
Total Expenses Including Fuel	**391**	**386**	**340**	**316**
Capacity Factor (%)	85	85	85	85
Net Station Efficiency (%)	20	20	25	30

* Fuel cost ($/t) for forest thinnings and timber stand improvement = $40/BDT

Figure 3 Capital cost breakdown of stoker boiler combustor [9]

Capital Costs of Stoker Boiler

- Project & Process Contingency, 11%
- Owners costs, 4%
- Fuel Handling System, 9%
- Boiler, 22%
- General Facilities & Engineering Fee, 23%
- Balance of Plant (Emission controls, etc), 14%
- Baghouse & Cooling Tower, 5%
- Steam Turbine & Auxiliaries, 11%
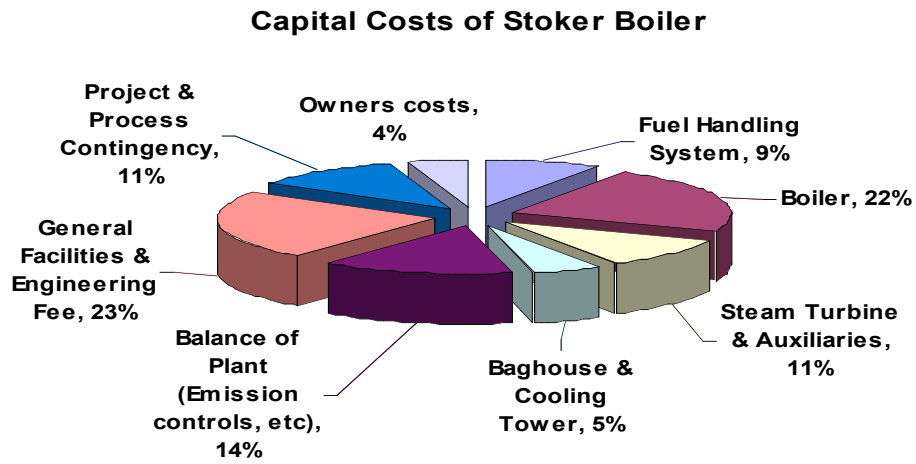
Table 2. Capital and O&M costs (2004$), capacity factors, and efficiency of stoker boiler combustor[10]

Technology	25 MW Stoker Boiler			
Year	2005	2007	2010	2017
Installed Capital Cost ($/kW)				
Fuel Handling System	208	204	191	173
Boiler	537	526	493	448
Steam Turbine & Auxiliaries	255	250	234	213
Baghouse & Cooling Tower	118	116	108	99
Balance of Plant (Emission controls, etc)	340	333	312	284
General Facilities & Engineering Fee	560	549	514	467
Project & Process Contingency	276	270	253	230
Owners costs	105	103	96	88
Total Capital Cost	**2400**	**2350**	**2200**	**2000**
Operation and Maintenance Cost ($/kW-yr)				
Fuel Cost ($/t)	22.05	22.05	20.00	20.00
Labor Cost	74	72	70	66
Maintenance Cost	55	54	52	52
Insurance/Property Tax	52	50	49	49
Utilities	7	7	7	7
Ash Disposal -use negative value for sales	4	4	3	3
Management/Administration	7	7	7	7
Other Operating Expenses	15	14	14	14
Total Non-Fuel Expenses	**213**	**209**	**203**	**199**
Total Expenses Including Fuel	**372**	**368**	**318**	**295**
Capacity Factor (%)	**85**	**85**	**85**	**85**
Net Station Efficiency (%)	**20**	**20**	**25**	**30**

Figure 4. Capital cost breakdown of gasifier (BIGCC)[11]

Capital Costs of Gasifier
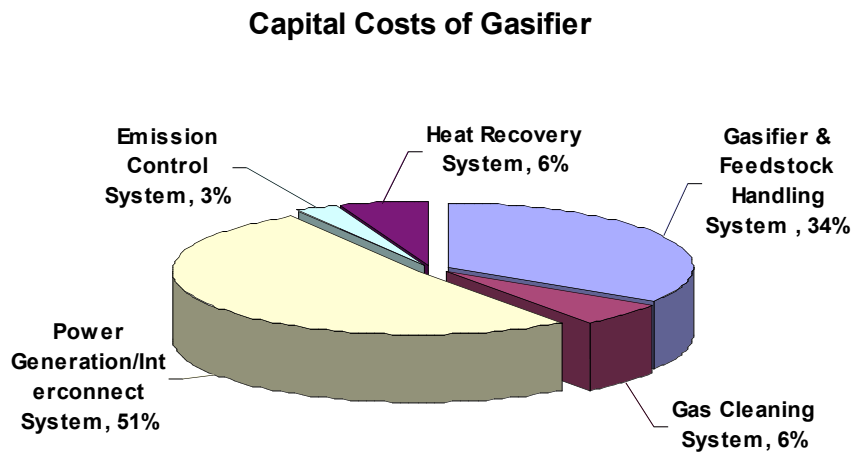
Table 3. Capital and O&M costs (2004$), capacity factors, and efficiency of gasifiers (BIGCC) [12]

Technology	25 MW Gasifier (BIGCC)		
Year	2005	2010	2017
Installed Capital Cost ($/kW)			
Gasifier & Feedstock Handling System	959	600	514
Gas Cleaning System	161	100	86
Power Generation/Interconnect System	1,439	900	771
Emission Control System	80	50	43
Heat Recovery System	161	100	86
Total Facility Capital Cost	**2,800**	**1,750**	**1,500**
Operation and Maintenance Cost ($/kW-yr)			
Biomass Fuel Cost ($/t)	22.05	20	20
Dual Fuel Cost ($/L)	0	0	0
Labor Cost	82	80	78
Maintenance Cost	61	60	58
Waste Treatment/Disposal	0	0	0
Insurance/Property Tax	58	56	54
Utilities	8	8	8
Management/Administration	8	8	8
Other Operating Expenses	17	16	16
Total Non-Fuel Expenses	**233**	**227**	**222**
Total Expenses Including Fuel	**386**	**371**	**358**
Capacity Factor (%)	**90**	**90**	**90**
HHV Efficiency of Gasification System--Biomass to Clean Gas (%)	**65**	**65**	**65**
Net HHV Efficiency of Power Generation	**34**	**36**	**38**
Overall Net System Efficiency (%)	**22.1**	**23.4**	**24.7**

Figure 5 Capital cost breakdown for landfill gas to energy [13]

Capital Costs of Landfill Gas/Power Generation
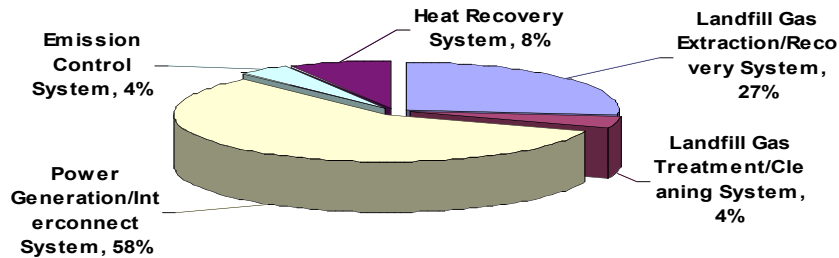
Table 4. Capital and O&M costs (2004$), capacity factors, and efficiency of landfill gas to energy

Technology	Landfill Gas/Power Generation		
Year	**2005**	**2010**	**2017**
Installed Capital Cost ($/kW)			
Landfill Gas Extraction/Recovery System	350	296	269
Landfill Gas Treatment/Cleaning System	50	42	38
Power Generation/Interconnect System	750	635	577
Emission Control System	50	42	39
Heat Recovery System	100	85	77
Total Facility Capital Cost	**1,300**	**1,100**	**1,000**
Operation and Maintenance Cost ($/kW-yr)			
Landfill Gas Fuel Cost--if purchased	0	0	0
Dual Fuel Cost	0	0	0
Labor Cost	101	92	89
Maintenance Cost	11	10	10
Waste Treatment/Disposal	4	4	4
Insurance/Property Tax	2	2	2
Utilities	2	2	2
Management/Administration	2	2	2
Other Operating Expenses	2	2	2
Total Non-Fuel Expenses	**125**	**116**	**111**
Total Expenses Including Fuel	**125**	**116**	**111**
Capacity Factor (%)	**85**	**85**	**85**
Net HHV Efficiency of Power Generation incl. Dual Fuel (%)	**23**	**25**	**30**

Figure 6 Capital cost breakdown of dairy waste biogas[14]

Capital Costs of Dairy Waste Biogas/Power Generation

Emission Control System, 2%
Heat Recovery System, 6%
Power Generation System, 17%
Biogas Cleaning System, 1%
Digester & Feedstock Handling System, 74%
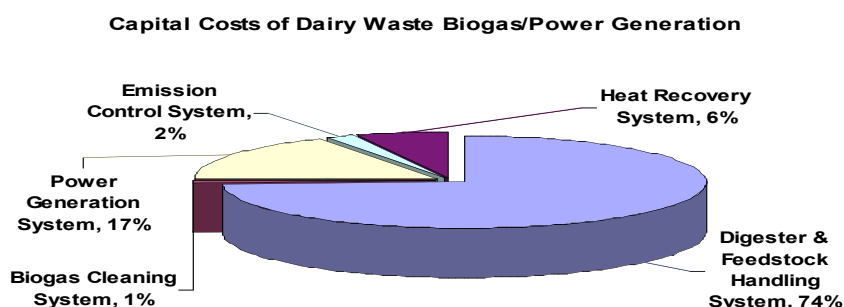
Table 5. Capital and O&M costs (2004$), capacity factor, and efficiency of dairy waste biogas[15]

Technology	200 kW Dairy Waste - Biogas/Power Generation		
Year	2005	2010	2017
Installed Capital Cost ($/kW)			
Digester & Feedstock Handling System	2,593	2,222	1,926
Biogas Cleaning System	43	37	33
Power Generation System	583	500	433
Emission Control System	65	56	48
Heat Recovery System	216	185	160
Total Facility Capital Cost	**3,500**	**3,000**	**2,600**
Operation and Maintenance Cost ($/kW-yr)			
Fuel Cost ($/t)	0	0	0
Labor Cost	200	150	75
Maintenance Cost	60	50	40
Insurance/Property Tax	25	25	20
Utilities	5	5	5
Management/Administration	5	5	5
Other Operating Expenses	5	5	5
Total Non-Fuel Expenses ($/y)	**300**	**240**	**150**
Total Expenses Including Fuel ($/y)	**300**	**240**	**150**
Capacity Factor (%)	**85**	**88**	**90**
Net Efficiency--Biogas to Electricity (%)	**23**	**27**	**30**

Table 6. Capital and O&M costs (2004$), capacity factor, and efficiency wastewater to biogas power generation

Technology	1000 kW – Wastewater Biogas/Power Generation		
Year	**2005**	**2010**	**2017**
Installed Capital Cost ($/kW)			
Digester & Feedstock Handling System	1,000	950	850
Biogas Cleaning System	16	10	10
Power Generation System	224	200	150
Emission Control System	26	20	18
Heat Recovery System	84	70	60
Total Facility Capital Cost	**1,350**	**1,250**	**1,088**
Operation and Maintenance Cost ($/kW-yr)			
Fuel Cost ($/t)	0	0	0
Labor Cost	100	100	100
Maintenance Cost	40	38	37
Insurance/Property Tax	20	18	16
Utilities	5	5	5
Management/Administration	5	5	5
Other Operating Expenses	5	5	5
Total Non-Fuel Expenses ($/y)	**175**	**171**	**168**
Total Expenses Including Fuel ($/y)	**175**	**171**	**168**
Capacity Factor (%)	**85**	**88**	**90**
Net Efficiency--Biogas to Electricity (%)	**23**	**27**	**30**

The LCOE's of these biomass energy conversion technologies were compared with the LCOE's of natural gas combined cycle to evaluate their cost competitiveness, both in current and constant dollars (2004 constant dollar). The LCOE's of biomass technologies and combined cycle in current dollar and the average wholesale prices of electricity were compared and plotted for years 2005, 2010 and 2017. The Energy Commission wholesale prices forecast[16] in 2003 and E3 CPUC forecast are reported in current dollars. The E3 CPUC forecast and LCOE's of combined cycle were done by Energy and Environmental Economics, Inc. (E3) and are consistent with the methodology and inputs adopted for the California Public Utilities Commission Avoided Cost proceeding in Rulemaking 04-04-025, April 7, 2005. Details of the methodology and input assumptions can be found on the E3 website at http://www.ethree.com/cpuc_avoidedcosts.html. The 2004 market price referent (MPR) for RPS for 10-, 15-,and 20-year is set at $0.0605/kWh, reflecting a

correction to current or nominal dollar basis from an inflation-adjusted constant dollar basis.

Evaluate MW solutions that will meet RPS targets by 2010 and 2017

The criteria used to evaluate the MW solutions that will meet RPS targets by 2010 and 2017 were the LCOE's and the transmission single system reliability called AMWCO. When a base year contingency analysis is performed, an AMWCO value can be calculated. This is the base value from which all biomass technologies can be compared for a given year. For each biomass technology simulation completed, another AMWCO is calculated. When the difference between the two AMWCO values are divided by the capacity of the renewable technology being evaluated, the resulting value is the transmission impact ratio. A negative impact ratio indicates that the installation of the renewable technology at the evaluated connection point resulted in an improvement in transmission reliability. A positive value results in a decrease in transmission reliability.

Public benefits such as environmental, economic and other non-energy benefits were assessed and considered in the SVA approach.

Discussion

Biomass Resources

Recent biomass resource estimates by the California Biomass Collaborative shows that California has prevalent, widespread and diverse biomass supplies.

The gross annual resource for year 2005 is estimated at more than 86 million bone dry tons (BDT)[17].

After employing all the filters, about 34 million BDT per year are perhaps technically available for power production[18, 19] (See Table 7). This technical potential became the basis to further estimate what is economically feasible. It is important to note that, of the gross annual resource, 25 percent is from agriculture, 31 percent from forestry, and 44 percent from municipal solid wastes. Supplementing the in-state biomass production is imported biomass in packaging and other materials accounted for in the waste stream. Landfill gas production exceeds 118 billion cubic feet per year (BCF/y) from more than 1 billion tons of waste in-place, with a potential recovery of 79 billion BCF/y. Biogas from waste-water treatment plants adds 16 - 18 BCF/y. Dedicated energy crops are not grown to any significant extent in the state presently, but might be produced in the future, particularly in association with reclamation of drainage and other impaired agricultural lands in the San Joaquin Valley. Wastes volumes are

expected to increase over time due to population growth, legislation establishing regulatory limitations on manure and landfill management, and efforts to reduce wildfire risks by removing forest residues.

By 2017, gross annual biomass production might approach 100 million BDT, with about 40 million BDT technical potential.

Table 7. Estimates[2] of gross and technical available biomass in California, 2005.

(Million dry tons/year except as noted)	Gross[c]	Technical[c]
Total Biomass	**86.0**	**33.6**
Possible Use by Thermal Conversion	69.3	28.9
Possible Use by Biochemical Conversion	16.7	4.6
Total Agricultural	**21.6**	**9.6**
Total Animal Manure	11.8	4.5
Total Cattle Manure	8.3	3.0
Milk Cow Manure	3.8	1.9
Total Orchard and Vine	2.6	1.8
Total Field and Seed	4.9	2.4
Total Vegetable	1.2	0.1
Total Food Processing	1.0	0.8
Total Forestry	**26.8**	**14.3**
Mill Residue	6.2	3.3
Forest Thinnings	7.7	4.1
Logging Slash	8.0	4.3
Chaparral	4.9	2.6
Total Municipal	**37.6**	**9.7**
Biosolids Landfilled	0.1	[b]
Biosolids Diverted	0.6	0.5
Total MSW Biomass Landfilled	18.5	[2]
Total MSW Biomass Diverted	18.4	9.2
Landfill gas	118 BCF/y [a]	79 BCF/y
Biogas from waste-water treatment plants (WWTP)	16 BCF/y[c]	11 BCF/y

[a] Total landfill gas potential is 118 billion cubic feet per year (BCF/y) for an assumed composition of 50% methane from waste already in place. Diversion of MSW shown as landfilled will reduce future landfill gas potential but may increase generating capacity through use of conversion technologies. Increased diversion would also support potential increases in biofuels.

[b] assumed landfilled, resource available as landfill gas.

[c] billion cubic feet per year of biogas (60% methane).

[d]Gross resource refers to total estimated annual biomass produced. Technical resource refers to the amount that can potentially be supplied to utilization activities.

Biomass Energy Conversion Technologies

Three principal routes exist for converting biomass: 1) thermochemical, 2) biochemical, and 3) physicochemical. In practice, combinations of these routes may be used.
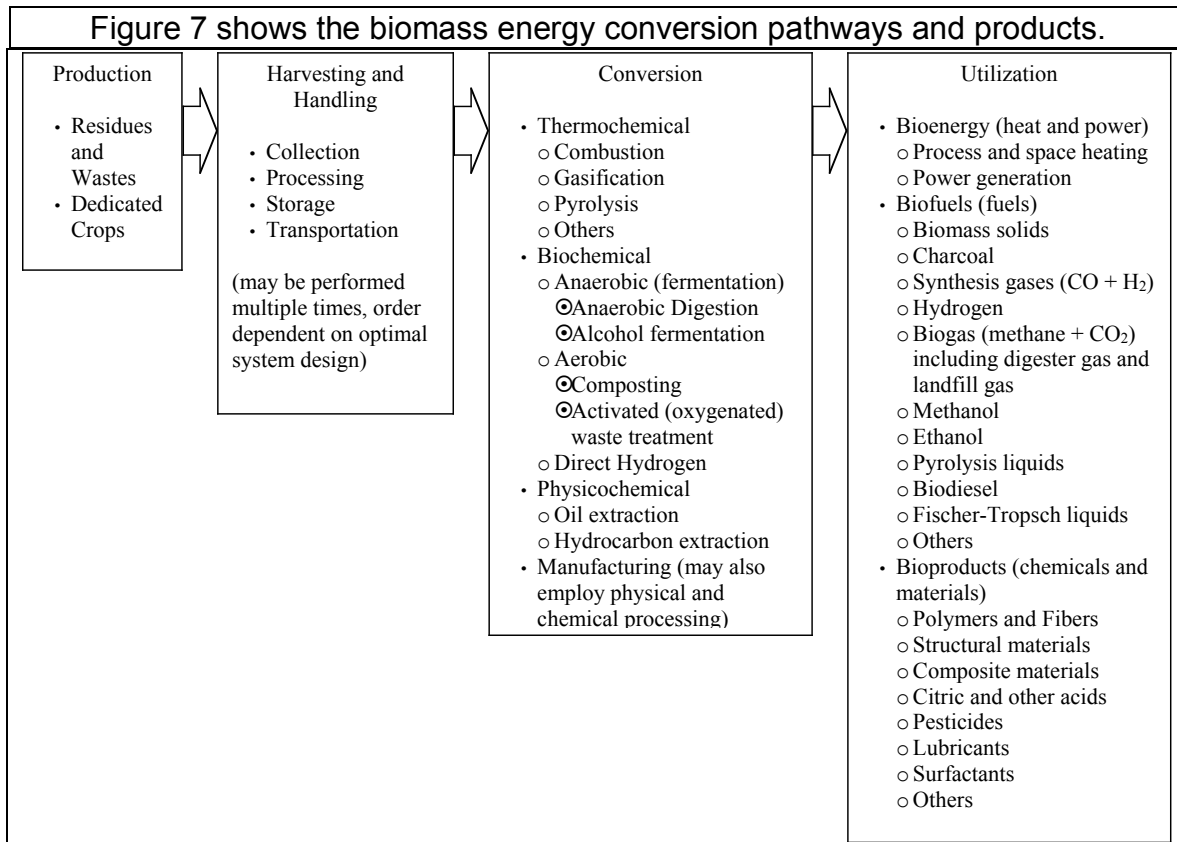
Thermochemical conversion: Combustion, thermal gasification, and pyrolysis are classified as thermochemical conversion along with a number of variants involving microwave, plasma arc, supercritical fluid, and other processing techniques generally occurring at elevated temperatures. Products include heat, fuel gases, synthesis gases, ammonia, hydrogen, alcohols, Fischer-Tropsch hydrocarbons, other liquids, and solids. Thermochemical techniques tend to be high rate as compared with biochemical processes and relatively non-selective for individual biomass components in that the chemically complex biomass is substantially degraded into simple compounds. Thermochemical techniques are also being developed for the purpose of producing ethanol from cellulosic biomass such as wood and straw. Byproducts include ash, chars, and liquid effluents for disposal or recovery as commercial products.

Biochemical conversion: Conversion systems using biological processes include fermentation to produce alcohols, fuel gases (such as methane by anaerobic digestion), acids and other chemicals, and aerobic processes used for waste stabilization and composting. Anaerobic and other biological processes are also being explored for the production of hydrogen. Byproducts include organic solids and liquid effluents. Where feedstocks are uncontaminated by heavy metals or other toxic compounds not degraded by the process, byproducts can be recovered as commercial products for uses including animal feeds, fertilizers, and soil amendments. Proper handling and sterilization is required for by-products from processes employing genetically modified or recombinant organisms.

Physicochemical conversion: Among the physicochemical methods are alkaline and acid processes, esterification, mechanical milling, steam and ammonia freeze explosion and other explosive decompression processes. Pressing and extrusion, many times in combination with a biochemical or thermochemical reaction process, are also included in this class. A major new industry is developing around vegetable and waste oils to manufacture biodiesel as a substitute diesel engine fuel.

Advances in thermochemical processing and biotechnology are allowing greater selectivity for higher value products. Biorefineries are a major research and development focus for extracting high value materials and energy from biomass in integrated processing facilities.

Figure 7. Production, handling, conversion, and utilization pathways for biomass to energy and products.

Figure 7 shows the biomass energy conversion pathways and products.

Production	Harvesting and Handling	Conversion	Utilization
Residues and Wastes Dedicated Crops	Collection Processing Storage Transportation (may be performed multiple times, order dependent on optimal system design)	Thermochemical o Combustion o Gasification o Pyrolysis o Others Biochemical o Anaerobic (fermentation) ⊙Anaerobic Digestion ⊙Alcohol fermentation o Aerobic ⊙Composting ⊙Activated (oxygenated) waste treatment o Direct Hydrogen Physicochemical o Oil extraction o Hydrocarbon extraction Manufacturing (may also employ physical and chemical processing)	Bioenergy (heat and power) o Process and space heating o Power generation Biofuels (fuels) o Biomass solids o Charcoal o Synthesis gases (CO + H$_2$) o Hydrogen o Biogas (methane + CO$_2$) including digester gas and landfill gas o Methanol o Ethanol o Pyrolysis liquids o Biodiesel o Fischer-Tropsch liquids o Others Bioproducts (chemicals and materials) o Polymers and Fibers o Structural materials o Composite materials o Citric and other acids o Pesticides o Lubricants o Surfactants o Others

Environmental and Social Drivers

In addition to the energy and product value of biomass resources, interest in increasing utilization has accompanied concerns over environmental impacts and risks of many current management practices. Biomass development can have substantial impact on local economies and influence infrastructure requirements. Among the perceived benefits of biomass utilization are:

Improved management of greenhouse gas emissions.
Reduced dependency on imported energy sources.
Waste reduction .
Improvements in air and water quality.
Reclamation of degraded soils and lands.
New economic opportunities for agriculture and other industries.
Reduced severity and risk of wildfire.
Improved forest health and watershed protection.

Revitalization of urban and rural communities and creation of new jobs. Local grid support from distributed generation.

Biomass energy conversion, like wind, solar, and other renewable energy sources, is essentially carbon neutral. For biomass, this means that CO_2 released to the atmosphere in conversion processes such as combustion is offset by an equal amount used in growing new biomass through photosynthesis with no net increase in atmospheric CO_2. To be sustainable, biomass production and use must be "closed-loop," so that the amount of biomass grown is equal to that consumed. Biomass can also be used as a shorter-term carbon sequestration technique leading to net removal of CO_2 from the atmosphere when more biomass is grown than used or consumed in wildfires and decay. Carbon is also sequestered in biomass products such as lumber used in construction. Eventually, however, the carbon is released again as the biomass decays, burns, or is converted to energy. Net carbon reductions can also occur through the production of hydrogen and sequestration of carbon from biomass. Decarbonization of fossil fuels, as in the production of hydrogen from coal and natural gas to allow the use of the energy without the emission of greenhouse gases, will reduce carbon emissions to the atmosphere if the carbon is somehow sequestered. This technique cannot offer the same benefits as biomass in directly reducing carbon concentrations in the atmosphere. The most obvious and simplest approach to carbon sequestration, leaving fossil resources in the ground, does not capture the energy content and requires major short-term shifts in energy supply. California contributes to greenhouse gas emissions through fossil fuel use as well as deforestation. Approximately 60,000 acres per year of forest in the state are lost to other uses, a rate that is currently increasing.[20] This trend also contributes to increased fire risk due to urban development at the wildland interface. Reforestation is an important component of sustainable resource management, and will involve similar biomass management issues facing other portions of the state's forests.

If biomass is used sustainably instead of natural gas to generate electricity, at today's efficiencies every ton of biomass burned avoids 0.4 tons of CO_2 emission from natural gas. Increasing biomass conversion efficiencies will further reduce CO_2 emissions. Over the next century, continuing increases in atmospheric CO_2 will be dominated by fossil fuel use.[21] Climate changes are already apparent, and, continued unchecked, these practices will result in severe economic and social consequences well before fossil resources are exhausted.[22] Mitigating global climate change impacts associated with greenhouse gas emissions has been and continues to be an important motivation for bioenergy development around the world.

Reducing waste disposal is also an important driver for biomass development. Each year, approximately 1.5 million BDT of urban fuels, mostly wood, are separated from the waste stream and used as biomass fuel for power generation.

Assembly Bill 939 (1989), mandated a 50 percent solid waste diversion rate by 2000. This rate has not yet been achieved (Figure 8). After reaching a peak of 48 percent in 2002 and declining to 47 percent in 2003. The diversion accomplished to date has extended the projected lifetime of existing landfills, but total disposal has not decreased over the last ten years. Instead, increasing diversion is associated with increasing waste generation arising from state population growth and increasing per capita waste generation.[23]

An assessment conducted by the California Integrated Waste Management Board (CIWMB) in 2002 indicates a remaining 35-year landfill capacity.[24] The 43 permitted urban landfills in the state have a combined remaining lifetime of 12 years, while 132 non-urban sites have a capacity of 66 years, including the Eagle Mountain and Mesquite landfills, which are not currently operating. If the latter two are excluded, non-urban fill capacity extends 22 years. The 17 landfills in the Los Angeles area have a lifetime of 9 years. Within the 2017 timeframe of the RPS, waste jurisdictions will need to make decisions regarding future waste disposal. These conditions have led the CIWMB[25] and a number of jurisdictions to investigate alternatives, including waste conversion. A key limitation in this regard are the current technology designations concerning waste transformation and conversion. Lack of diversion credit for many technologies creates a considerable economic disadvantage as jurisdictions are unwilling to support development that does not result in compliance under AB 939. The issue of conversion is also subject to contentious public debate and particular opposition to incineration and other thermochemical technologies. Despite these concerns, the resource value of biomass in solid waste constitutes a considerable potential for economic development and environmental improvement.

Figure 8. Solid waste generation, disposal, and diversion in California, 1989-2003.[26]
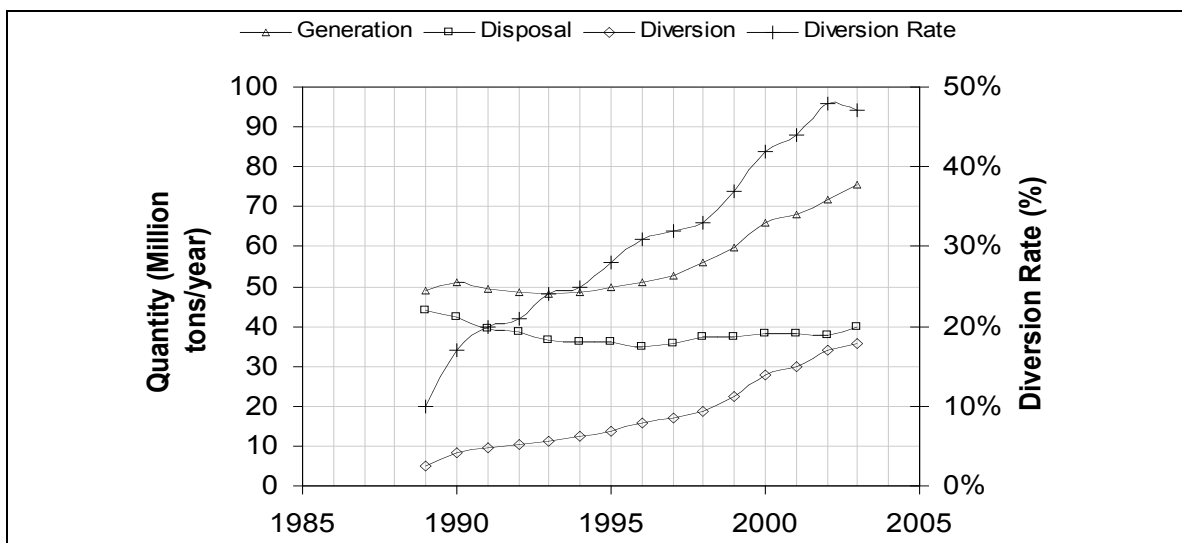
Air pollution from agricultural and forest burning has long been an issue supporting bioenergy development. Emissions from wildfires have become

increasingly so. Emissions of criteria pollutants from agricultural burning, range improvement fires, prescribed forest fires, and wildfires are listed in Table 8. Total emissions from wood-fired boilers in California are shown for comparison. Total tonnages are quite different, and emissions vary by season. Wildfire emissions occur primarily during the summer, with 97 percent of emissions occurring between May and October. Average aggregate annual wildfire emissions exceed 1.1 million tons per year (Table 9).[27] For criteria pollutants, biomass power plants employing modern circulating fluidized bed boilers realize emission reductions for all species compared with agricultural burning (Table 9), although at present straw and other field crop residues are not used in California power plants because of problems with ash fouling. Emission reductions for wildland fires are similar. Biomass utilization results in substantial emission reductions for CO, hydrocarbons, and particulate matter compared with open fires. Emissions for all criteria pollutants from existing biomass boilers in the state amount to 0.1 percent of total statewide emissions, whereas agricultural, range, and prescribed forest fires account for 5 percent and wildfires 10 percent of total statewide emissions.

Table 8. Air pollutant emissions from agricultural, range, and forest burning, wildfires, and wood-fired boilers, 2004 inventory (10 year annual average tons/day).[28]

	TOG	ROG	CO	NOx	SOx	PM	PM10	PM2.5	Total
Agriculture—Prunings	13.3	7.6	74	3.8	0.01	8.9	8.7	8.2	100
Agriculture—Field	20.5	11.7	142	1.8	0.18	17.2	16.9	16.2	182
Total Agricultural	33.8	19.3	216	5.6	0.19	26.1	25.6	24.37	282
Range Improvement	41.2	23.5	309	3.7		46.1	45.3	43.0	400
Forest Management	49.8	28.4	720	6		54.2	52.1	46.3	830
Total Ag, Range, Forest	124.8	71.2	1,245	15.3	0.19	126.4	123	113.7	1,512
Wildfires	273.0	128.4	2,482	79.38	24.46	362.0	253.4	215.0	3,221
Wood-fired boilers	0.83	0.37	24.49	5.05	0.48	1.12	1.12	1.04	32
Total Statewide	8,720	4,743	16,293	3,270	279	4,079	2,361	995	32,642

TOG=total organic gases, ROG=reactive organic gases, CO=carbon monoxide, NOx=oxides of nitrogen, SOx =oxides of sulfur, PM=total particulate matter, PM10=particulate matter of aerodynamic size class 10 m and less, PM2.5=particulate matter of aerodynamic size class 2.5 m and less.

Table 9. Emission factors (lb/MMBtu of fuel energy) for agricultural field crops, tree prunings, and circulating fluidized bed (CFB) boilers in California.[29]

	Average-Field	Average-Wood	Average-Ag	CFB	Ag/CFB
CO	7.96	4.77	6.89	0	2,963
NOx	0.33	0.41	0.36	0.06	6.36
SOx	0.04	0.01	0.03	0.01	2.9
ROG	0.85	0.53	0.74	--*	31,800
PM10	0.78	0.43	0.66	0.01	47.5

*$<2 \times 10^{-5}$.

Emissions of dioxins and furans have been of particular concern for solid waste incineration. Improvements in incineration and emission control technology resulted in a greater than 99 percent reduction in dioxin emissions from MSW incinerators in the US between 1990 and 2000; so this source represents less than 1 percent of all dioxin/furan emissions in the nation.[30] Residential wood burning and backyard refuse incineration are one and two orders of magnitude larger in contributions of dioxins to the environment. Despite these improvements, solid waste mass-burn facilities remain subject to considerable public scrutiny and opposition, and advanced conversion systems will likely be needed. Limited environmental data exist for many of these systems.

SB 700 (2003) eliminated agricultural exemptions from the Clean Air Act and now requires dairies and other agricultural operations over certain size thresholds to obtain air permits. Anaerobic digestion is proposed as best available control technology for ROG from new dairies with herd sizes above 1,984 animals. The production of biogas creates opportunities for power generation and a number of facilities have been installed under programs financed by the state. Conventional reciprocating engines used at most of these sites cannot meet 2007 standards for NOx, which could lead to simple flaring of the biogas rather than productive utilization. This has motivated investigations into ways to meet emission requirements or upgrade the gas for other uses, such as transportation fuel.

Green-e green electricity certification excludes combustion of municipal solid wastes in all regional standards, although in California municipal solid waste conversion facilities using non-combustion processes are eligible as long as they meet requirements for the RPS.[31] Other regions of the country exclude certain other forms of biomass from green electricity certification, including herbaceous agricultural waste and forestry biomass (except for mill residue in the Mid-Atlantic region), and waste wood from landscape operations in Illinois. Treated woods, such as chromated copper arsenate (CCA) treated materials, are excluded in the New England, New York, Mid-Atlantic, Texas, and Ohio standards, and railroad ties and construction and demolition debris are excluded in the Illinois standard. Most standards set maximum emission levels for certification.

Environmental issues are principally behind the drive to find new ways to manage dairy manure and other animal, food, and green wastes in the state. The state Dairy Power Production program, funded by the legislature through the California Energy Commission, was initiated to support both power generation from biogas produced from dairy manure digestion and to mitigate air and water quality impacts associated with conventional management techniques.[32] Although biogas systems are generally recognized as providing environmental benefits when properly implemented, concerns remain over the use of public funds to support development. A recent Sierra Club guidance document, for example, opposes public subsidies to methane digesters and other energy generation facilities at large confined animal feeding operations (CAFOs) for reasons of environmental protection, animal health, and public safety.[33]

Economic and ecosystem losses due to intense wildfires has also stimulated interest in improving forest management and increasing wood utilization. Approximately 1 million housing units in California are within wildland-urban interface or wildland areas.[34] The total estimated replacement value is $107 billion for structures alone. Between 1985 and 1994, an estimated 703 homes were lost annually to wildfire in California. The average loss per home burned is estimated at $232,000, and the average total annual loss for California is $163 million.

The State Board of Forestry and Fire Protection lists 2.2 million acres as being at extreme risk of wildfire, and more than 15 million acres at very high risk.[35] On average since 1950, more than 250,000 acres of forest and rangeland have been affected by wildfire each year. Over the last five years the average annual area burned exceeded 500,000 acres in approximately 10,000 wildfires. Average annual wildfire-related costs in California for local, state, and federal agencies exceeded $900 million per year. Expanding urban development in wildland-urban-interface areas creates increasing risk from fire. Drought and bark beetle infestations have exacerbated these problems in the southern regions of the state, contributing to devastating fires in the fall of 2003 that also cost 22 lives. Reducing fuel loads in forests greatly reduces these risks but produce large amounts of biomass disposal or utilization. Economic benefits of fuel load reduction can exceed treatment costs. Treatment benefits for areas at high fire risk have been estimated at $2,063 per acre, with treatment costs at $580 per acre, yielding net benefits of $1,483 per acre.[36] Net benefits for areas at moderate risk are estimated at $706 per acre. Concerns include environmental impacts from harvesting activities including soil erosion, damage to remaining trees, sediments from roads, and changes in quality of wildlife habitat. Despite apparent benefits, forest management techniques remain controversial, especially where larger tree removals are proposed to economically support treatment operations. The federal Healthy Forest Initiative and the Healthy Forest

Restoration Act are targeted toward reducing fuel loads and fire risk, with the intent of treating more than 19 million acres in the US by the end of 2006.[37]

Fuel and feedstock acquisition, plant construction, and operation of conversion or processing facilities can have positive impacts on jobs creation, tax benefits, and local economic development. Many rural communities with high unemployment can benefit from agricultural and forest biomass operations, while solid waste separation, handling, and utilization activities can provide the same in urban areas with proper attention to environmental justice issues. The renewable energy sector generates more jobs per MW of electric power installed, per unit of energy produced, and per dollar invested than does the fossil fuel sector.[38] Estimates of the number of jobs vary, but for biopower typical values are in the range of 3 to 6 per MW_e installed.[39] For corn-to-ethanol facilities, direct employment runs 1 to 1.5 jobs per million gallons per year capacity, with total employment approaching 20 jobs/million gallons per year.[40] Increasing the share of biomass energy is likely to lead to job shifts in the energy sector from mining and related activities to agriculture. More comprehensive policies that recognize the complementary effects of renewable energy, energy efficiency, and other sustainable development are likely to lead to higher levels of employment overall.

Market Drivers and Incentives

Principal market drivers for biomass include the RPS, waste diversion requirements, reduced waste disposal costs, advantages and incentives for self-generation to avoid high retail prices of electricity, public goods charges and supplemental energy payments, federal tax credits, green pricing programs, and growing economic incentives associated with renewable energy credits and a developing carbon trading market.

The mandate to increase the share of renewable electricity in the state provides substantial incentives for development, but the RPS does not provide any essential mechanism discriminating among renewable resource options. The "least-cost and best-fit" criterion creates a competitive market environment in which lower cost resources are developed first, potentially without crediting other benefits to the state such as costs of forest fire suppression and reduced waste disposal.

Long term power purchase agreements (PPA) are critical to financing biopower systems, but these agreements are essentially unavailable outside successful bidding under the RPS. The development of the existing industry was largely a result of long-term favorable-price contracting available under Interim Standard Offer 4 following the enactment of PURPA. To gain market share under the RPS, biomass developers will need to find ways to generate at competitive costs, such as by reducing fuel costs or greater use of combined heat and power (CHP)

systems, or by benefiting from incentives and policies providing financial and economic credit for other attributes of biomass utilization.

An example of direct incentive support for biopower development is provided by the Dairy Power Production Program (DPPP). The program was initiated by the California Energy Commission (CEC) Public Interest Energy Research (PIER) program in response to Senate Bill 5X (2001) following the California energy crisis of 2000-2001. Among other things, SB5X provided $15 million in grants for pilot projects encouraging development of "bio-gas digestion power production technologies," with $10 million for the development of manure methane power projects on California dairies, and $5 million for peak power reduction grants through revision of system operations in anaerobic digestion of biosolids and animal wastes in Southern California. The DPPP provides two types of assistance: buydown grants that cover up to 50 percent of the capital costs of the system based on estimated energy production, and incentive payments based on 5.7 cents/kWh of electricity generated, totaling the same amount as a buydown grant paid out over five years. Buydown grants are capped at $2,000/kW. The DPPP is administered for the Commission by Western United Resource Development, Inc (WURD). The program is complemented or supplemented by other incentives provided by CEC PIER-targeted solicitations and programmatic grants, the availability of California Pollution Control Financing Authority and SAFE-BIDCO loans, and federal incentive programs including the Renewable Energy Systems and Energy Efficiency Improvements (RES-EEI) program through the USDA Rural Business-Cooperative Service and the USDA EQIP program. Section 319 of the federal Clean Water Act provides funds administered by the State Water Resources Control Board, and in accordance with Assembly Bill 970 the California Public Utilities Commission requires utilities to provide incentives to customers who install distributed generation systems under the Self-Generation Incentive Program.[41] Additional incentives for development have accompanied recent environmental regulation, including permitting requirements under Senate Bill 700 (2003). Net metering provisions under AB 2228 (2002) for dairy anaerobic digester systems have increased the economic attractiveness of these systems. Dairy net metering sunsets in 2006 unless extended by legislation. The loss of net metering constitutes a disincentive to continued development.

State solid waste diversion requirements would provide greater market incentive for waste conversion if more technologies were allowed diversion credit. Currently, jurisdictions are set at a minimum of 50 percent diversion, but this level has not been achieved statewide. Most conversion options are still considered under the transformation definition of the legislation and are therefore ineligible for full diversion credit-creating a disincentive for jurisdictions to pursue development of this alternative. This issue is currently being addressed under AB 2770.

The RPS requires production incentives or supplemental energy payments to cover above-market costs of renewables. Utilities are only required to pay up to an established market price referent. The CEC pays above market costs as supplemental energy payments provided by the Public Goods Charge fund. Supplemental energy payments (SEP) are available to existing biomass generators within the Tier 1 category of the Existing Renewable Facilities Program but are currently capped at $0.01/kWh above-market with a target price of $0.0537/kWh. SEPs may be insufficient to support the full implementation of the RPS.

Federal Section 45 production tax credits (PTC) extended under HR 4520 (American Jobs Creation Act, 2004) provide economic support for the use of renewable energy and refined coal (principally synfuels). Geothermal, solar, wind, and closed-loop biomass are allowed 1.8 cents/kWh credit.[42] Open-loop biomass, municipal solid waste, and small irrigation hydroelectric systems are eligible for half that amount, 0.9 cents/kWh. Refined coal is allowed a credit of $4.375/ton. Wind, closed-loop biomass, and refined coal can apply the credit over ten years, with all others for five years beginning October 22, 2004. Assets subject to the credit must be placed in service prior to 1 January 2006. The availability of the credit should attract financing for new biomass and other renewable projects, but the short time frame for development will limit the impact of the incentive if there is not an extension. Closed-loop credits have not been used so far in the U.S. Unequal treatment for open-loop (e.g. residue) biomass and biomass in solid waste results in a less competitive position relative to geothermal, solar, and wind resources.

Green-pricing programs also directly value renewable energy by allowing customer choice of the source of energy provided by utilities. Allowing customers direct access to green power suppliers provides a mechanism to pass through generation costs. California suspended direct access during the energy crisis of 2000-2001. Although green pricing was not specifically prevented, the impact of the direct access suspension had the effect of discouraging green marketing and resulted in an overall decline in green power purchases nationwide during 2002.[43] Biomass allowed within the Green-e certification standard for California includes woody wastes including mill residues, agricultural crops or wastes, animal and other organic waste, energy crops, and landfill gas.[44] As noted above, municipal solid waste conversion facilities using non-combustion processes are eligible as long as they meet requirements for the RPS. Co-firing of landfill gas and biogas is also allowed if separately metered and contracts allow certification.

Internationally, many countries signatory to the Kyoto Protocol have adopted policies to reduce greenhouse gas emissions and have put in place incentives that encourage greater use of biomass resources, including directives to reduce waste disposal in landfills, reduce landfill methane emissions, and expand producer responsibility for recycling and disposal of manufactured products.[45]

The U.S. has not yet ratified the agreement and so is not legally bound to meet emission reduction targets. The U.S. relies mostly upon strategies other than directly decreasing fossil fuel use and domestic greenhouse gas emissions.

Policies to reduce greenhouse gas emissions have typically focused on two mechanisms: carbon taxes and emissions trading. Carbon taxes are direct price-based instruments designed to increase the price of fossil fuels and reduce demand. Taxes are paid to governments which can return the tax revenue to the economy by reducing taxes on other activities, including renewable energy. With emissions trading, the right to emit becomes a tradable commodity. Trading caps fix the allowed emission level; firms that incur higher costs of emission reduction can purchase permits to emit from firms that have lower abatement costs and can reduce emissions below allowed levels, or credits from firms that do not emit, such as renewable energy generators.

Carbon taxes have not developed as a preferred approach in the U.S. Valuation of the renewable energy and environmental benefits is beginning to appear in the form of renewable energy credits or certificates (RECs), also known as tradable renewable energy certificates (TRCs) or green tags. RECs are a market mechanism designed to capture the environmental attributes of renewable energy and will have an important role in expanding future use of renewable resources, including biomass. Current values for RECs in the U.S. are well below environmental and social costs associated with non-renewable resource consumption.[46] RPS contracts in California require RECs to be bundled with energy delivery. REC value varies throughout the U.S. In California, the market is largely undeveloped. In other regions of the US, RECs trade at values as high as $0.03 – 0.05/kWh.[47]

Emission reduction credits (ERC) might provide economic incentives to biomass development but could also limit new installations. ERCs are in general an important part of New Source Review under the Clean Air Act. The value of emission reduction credits has been increasing.[48] NO_x transaction costs in California averaged $39,482 per ton in 2003, ranging from a low of $6,000 to a high of $140,000 per ton.[49] The average cost is nearly twice that incurred in 2000. For existing facilities, ERCs could help defray costs of equipment added to reduce emissions. Recent legislation (SB 705, 2003) curtailing agricultural burning potentially eliminates a number of emission credits previously available from this source which were used to permit many existing biomass facilities. The cost of purchasing ERCs could prove prohibitive to new facilities.

The environmental benefits associated with waste management aspects of biomass have led in some cases to the conclusion that biomass development should be handled primarily in that context. Such an approach, however, does not adequately address the multiple benefits that biomass provides, since some

previous approaches targeting mainly the renewable energy potential of biomass failed to integrate environmental attributes. It also ignores that part of biomass that is not waste. A management approach that recognizes both the resource value as well as the environmental benefits of biomass should be considered in creating more consistent policies and effective market incentives.

Short History of Biomass Energy Development

In 2003, biomass conversion accounted for more than 2 percent of electric generating capacity and energy in the state and a minor share of liquid fuels.[50] Biofuel use increased in 2004 due to the substitution of ethanol for MTBE in gasoline, but with the major share of ethanol coming from outside the state. Although electricity-generating capacity in the solid-fuel biomass combustion sector declined during the preceding decade, an increased capacity in landfill gas-to-energy kept total biomass capacity nearly constant at close to 1000 MWe in 2005.[51] (Figure 9)

Figure 9 California Biomass Installed Capacity (MWgross)
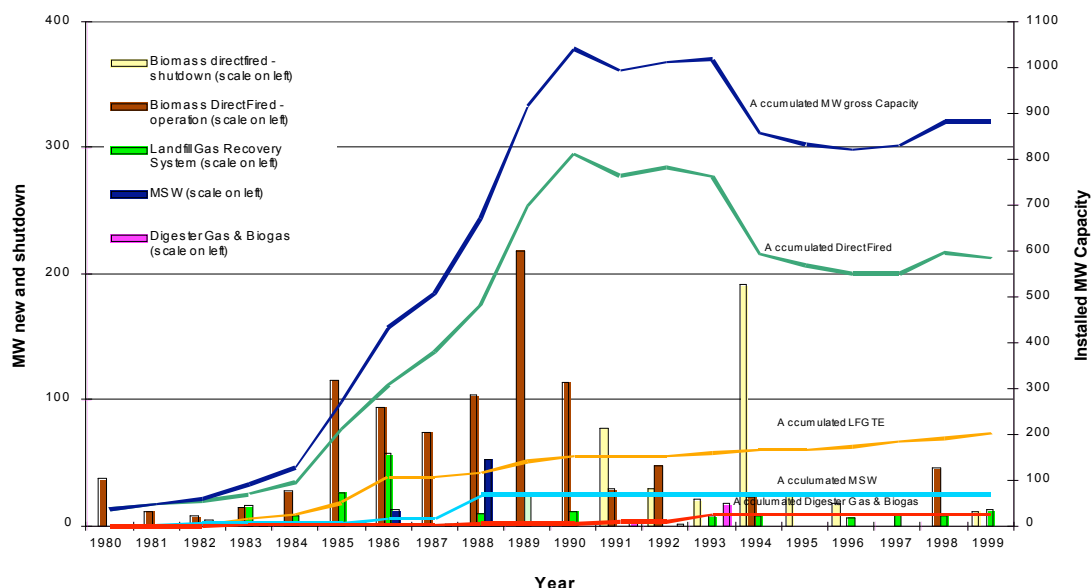
But while electricity consumption in the state continues to increase, electrical energy from biomass has stagnated since restructuring of the electric industry began in 1996 (see Figure 10). This stagnation in energy production has led to a declining share from biomass. Facility closures in the solid-fuel combustion sector have also resulted in greater amounts of biomass being landfilled or open-burned for disposal. The decline constitutes a fuel use reduction of approximately 1.5 million dry tons per year.[52] Biomass also declined in the share of renewable electricity that might be counted under the RPS, falling from 32 percent of renewable net system power in 2002 to 24 percent in 2003.[53] Although landfilling of biomass enables greater power generation from landfill gas and compensates

in part for the decline in the combustion sector, the trend is counter to state goals for reducing landfill disposal. Additionally, urban wood fuels and other materials that were once removed from the solid waste stream are now often landfilled, do not rapidly decompose in landfills. The slow rates of gas production in conventional landfill imply that generating capacity is not fully replaced. Disposal of biomass by open burning emits much higher levels of air pollutants than controlled combustion in biomass power plants and other conversion methods, and does not yield useful energy or products.[54]

Figure 10. Electrical Energy from Biomass and Gross System Power in California, 1982-2003[55]
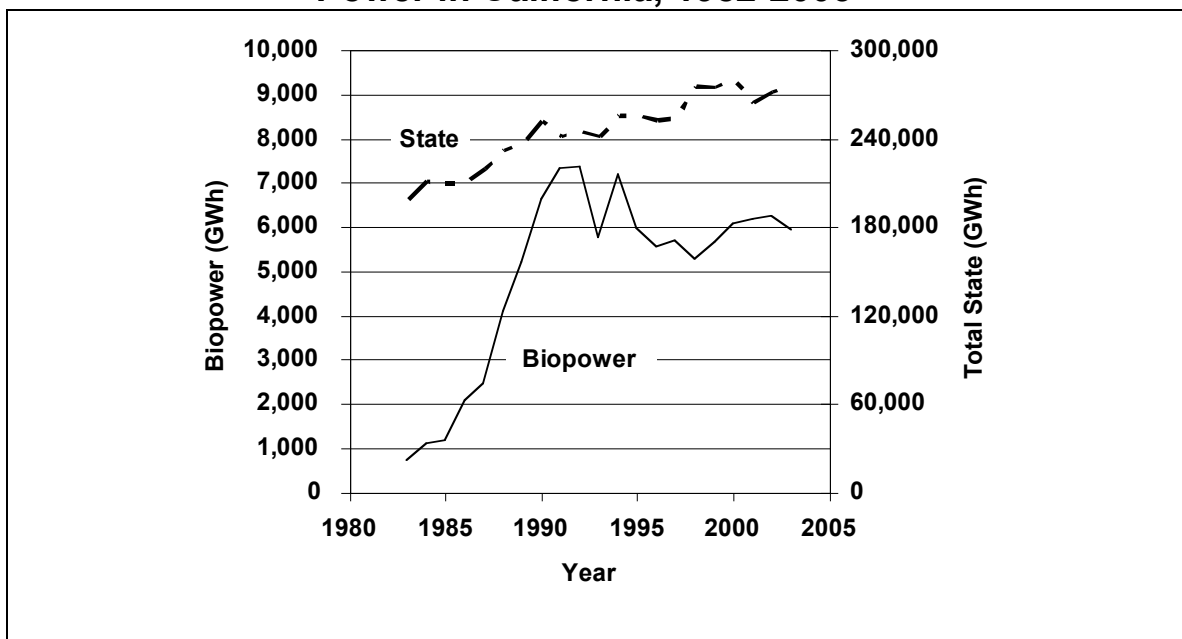
The biomass power industry in California started its commercial development in the early 1980's. PURPA and California's standard offer contracts (SO#s) provided biomass-to-energy technologies a strong market development force. By 1990, California had the world's largest and most diverse biomass power industry, with working capacity of over 1000 MW_e. Figure 9 shows the growth and decline of installed biomass electricity generating capacity in the state. This capacity peaked in 1990 from all biomass to electricity plants including direct-fired, landfill gas to energy, MSW, digester gas and biogas. The number of operating biomass power plants started to decline from 1991.

Of the 68 biomass direct-fired power plants originally constructed: 47 were fluidized bed, 18 were horizontal grates and 14 had moveable grates. LFGTE technologies used reciprocating engines, steam turbines and gas turbines. For anaerobic digestion, the commonly used technologies are complete-mix, plug flow and covered anaerobic lagoon using engine generator sets. To-date about

600 MW comes from 29 direct-fired facilities, 250 MW from 51 LFGTE, 68 MW from three MSW plants and 26 MW from eight digester gas and biogas. Figures 11 to 16 show the maps for these plants in California.

Figure 11. Total Operational Biomass Power Plants in California

OPERATIONAL BIOMASS POWER PLANTS IN CALIFORNIA
JUNE 2005

ENERGY GENERATION RESEARCH OFFICE
CALIFORNIA ENERGY COMMISSION

▲ Ag. Urban and Forest Residue Combustion
● Landfill Gas to Electricity
■ Municipal Solid Waste Combustion
● Animal Waste Anaerobic Digestion
● Sewage Wastewater Anaerobic Digestion

MSW Landfilled in 2003 (tons)
0 - 500,000
500,000 - 1,000,000
1,000,000 - 2,000,000
2,000,000 - 5,000,000
5,000,000 - 10,000,000

Figure 12. Ag. Urban and Forest Biomass Power Plants in California

OPERATIONAL AG. URBAN AND FOREST BIOMASS POWER PLANTS IN CALIFORNIA

JUNE 2005

ENERGY GENERATION RESEARCH OFFICE
CALIFORNIA ENERGY COMMISSION

Ag. Urban and Forest Residue Combustion
▲ 0 - 5 MW
▲ 5 - 10 MW
▲ 10 - 20 MW
▲ 20 - 30 MW
▲ 30 - 50 MW

MSW Landfilled in 2003 (tons)
0 - 500,000
500,000 - 1,000,000
1,000,000 - 2,000,000
2,000,000 - 5,000,000
5,000,000 - 10,000,000

Figure 13. Landfill Gas to Energy Plants in California

OPERATIONAL LANDFILL GAS POWER PLANTS IN CALIFORNIA

JUNE 2005

ENERGY GENERATION RESEARCH OFFICE
CALIFORNIA ENERGY COMMISSION

Landfill Gas to Electricity
- 0 - 1 MW
- 1 - 5 MW
- 5 - 10 MW
- 10 - 20 MW
- 20 - 50 MW

MSW Landfilled in 2003 (tons)
- 0 - 500,000
- 500,000 - 1,000,000
- 1,000,000 - 2,000,000
- 2,000,000 - 5,000,000
- 5,000,000 - 10,000,000

Figure 14. MSW Power Plants in California

OPERATIONAL MUNICIPAL SOLID WASTE POWER PLANTS IN CALIFORNIA

JUNE 2005

ENERGY GENERATION RESEARCH OFFICE
CALIFORNIA ENERGY COMMISSION

■ Municipal Solid Waste Combustion

MSW Landfilled in 2003 (tons)

- 0 - 500,000
- 500,000 - 1,000,000
- 1,000,000 - 2,000,000
- 2,000,000 - 5,000,000
- 5,000,000 - 10,000,000

Figure 15. Municipal Sewage Power Plants in California

OPERATIONAL MUNICIPAL SEWAGE SLUDGE POWER PLANTS IN CALIFORNIA

JUNE 2005

ENERGY GENERATION RESEARCH OFFICE
CALIFORNIA ENERGY COMMISSION
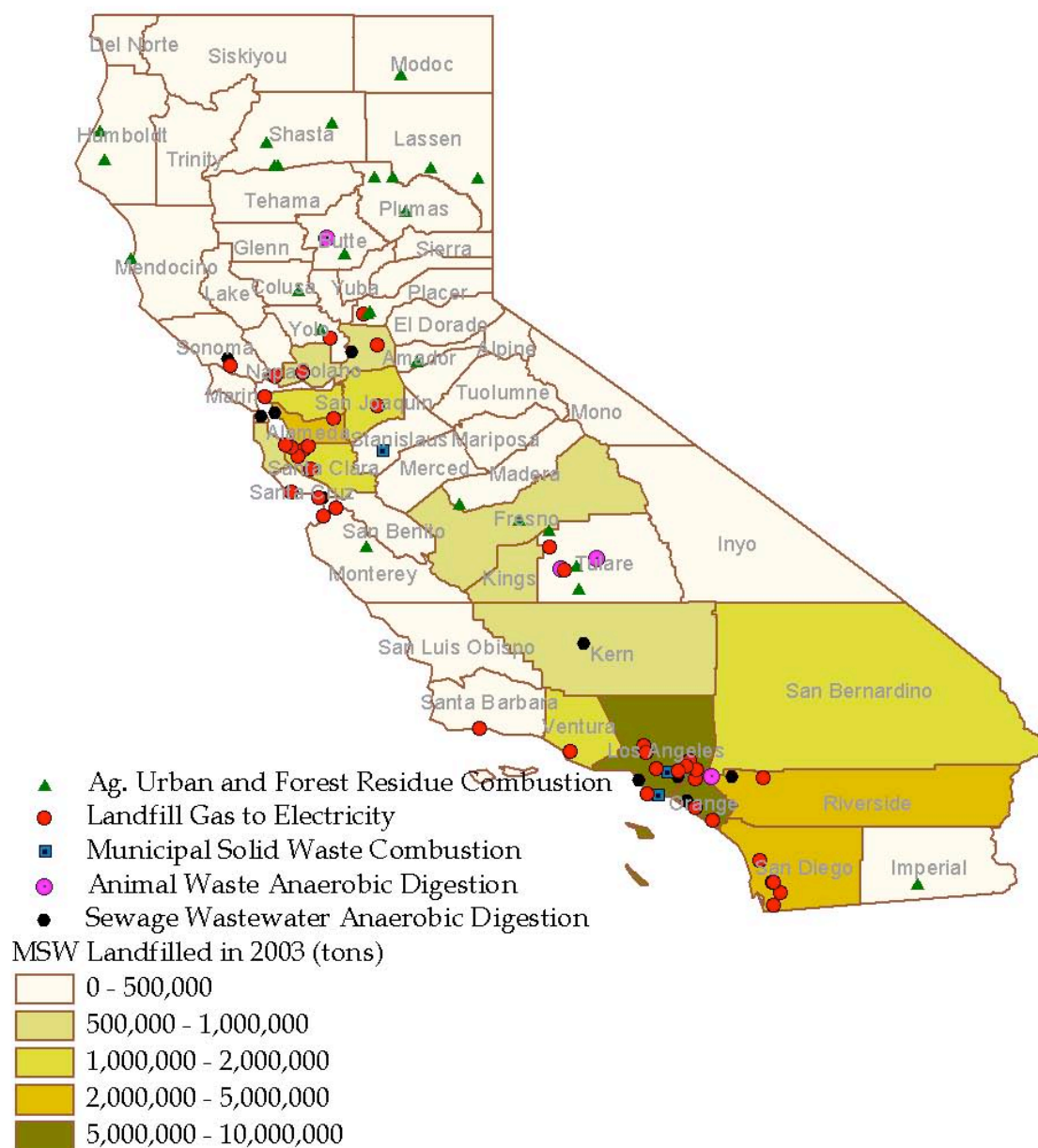
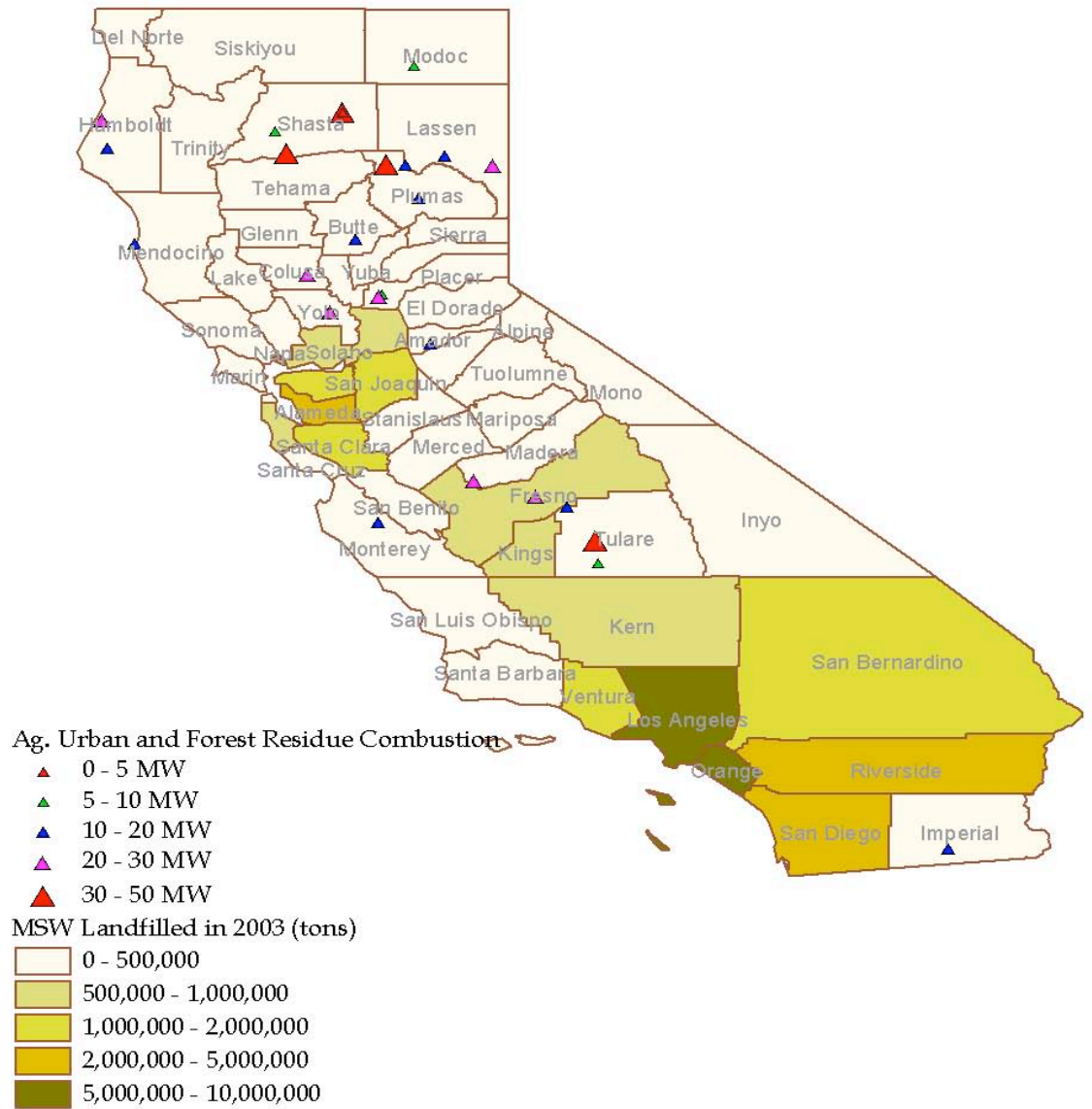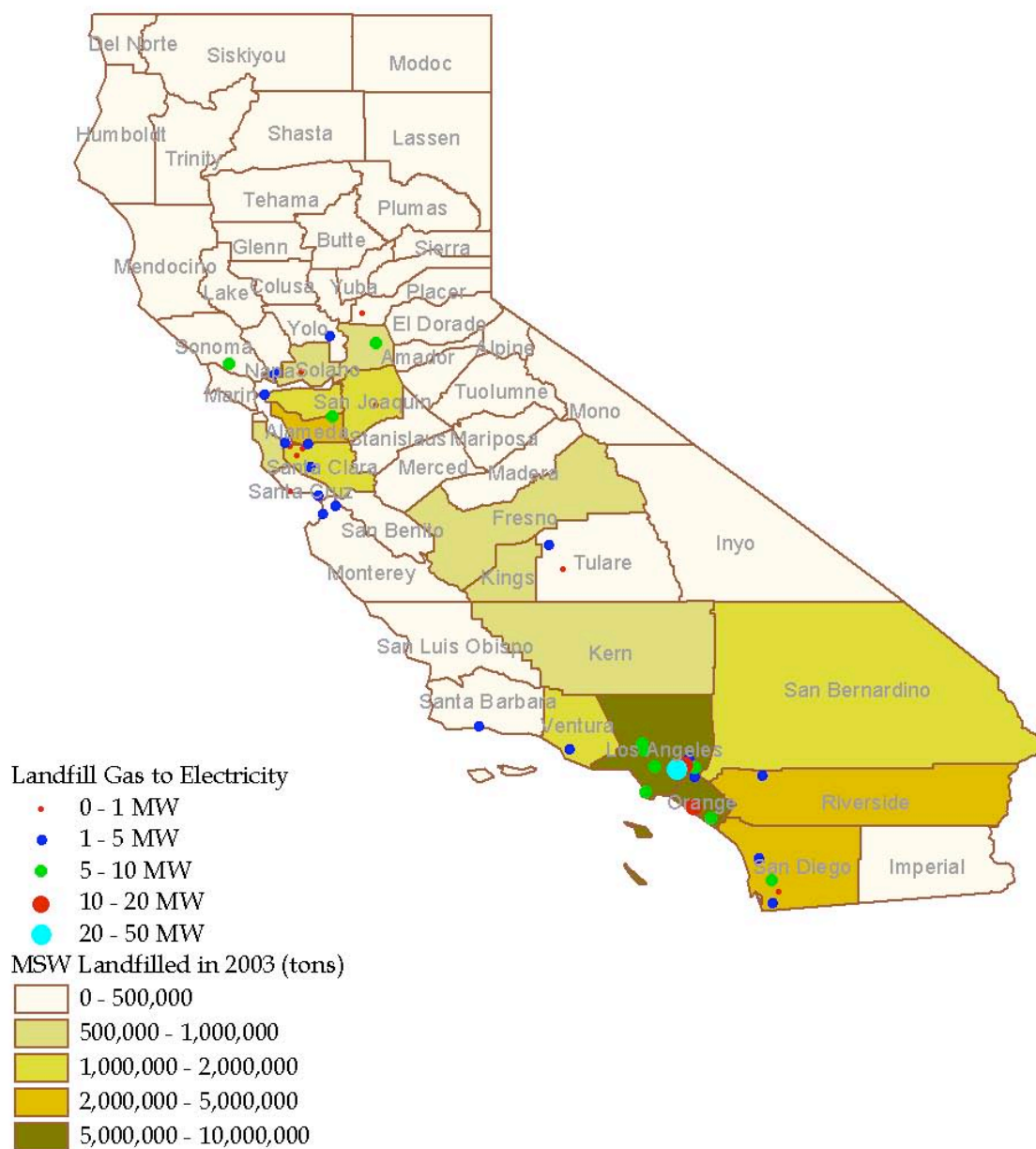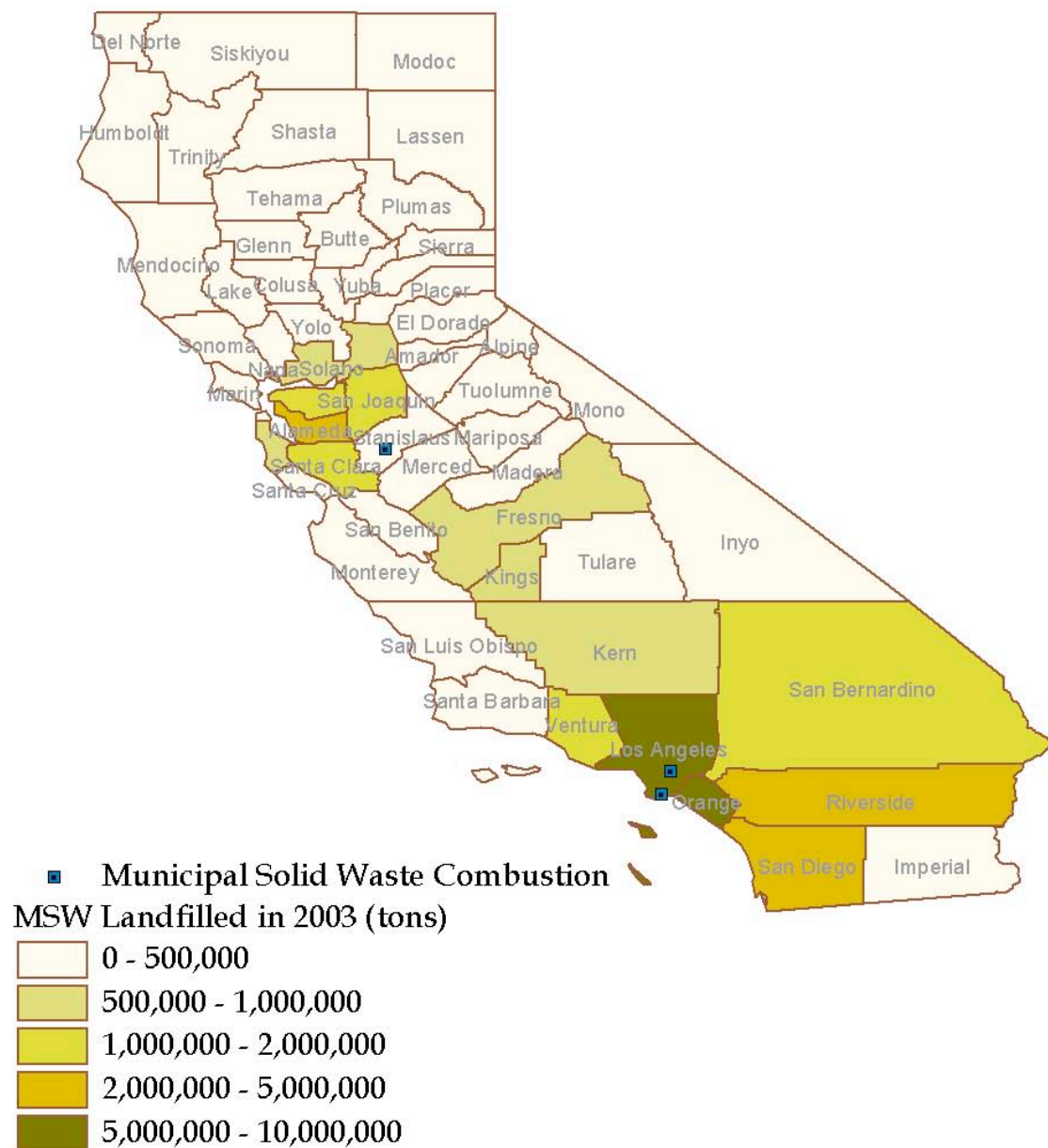Sewage Wastewater Anaerobic Digestion
- 0 - 0.5 MW
- 0.5 - 1 MW
- 1 - 3 MW
- 3 - 10 MW
- 10 - 15 MW

MSW Landfilled in 2003 (tons)
- 0 - 500,000
- 500,000 - 1,000,000
- 1,000,000 - 2,000,000
- 2,000,000 - 5,000,000
- 5,000,000 - 10,000,000
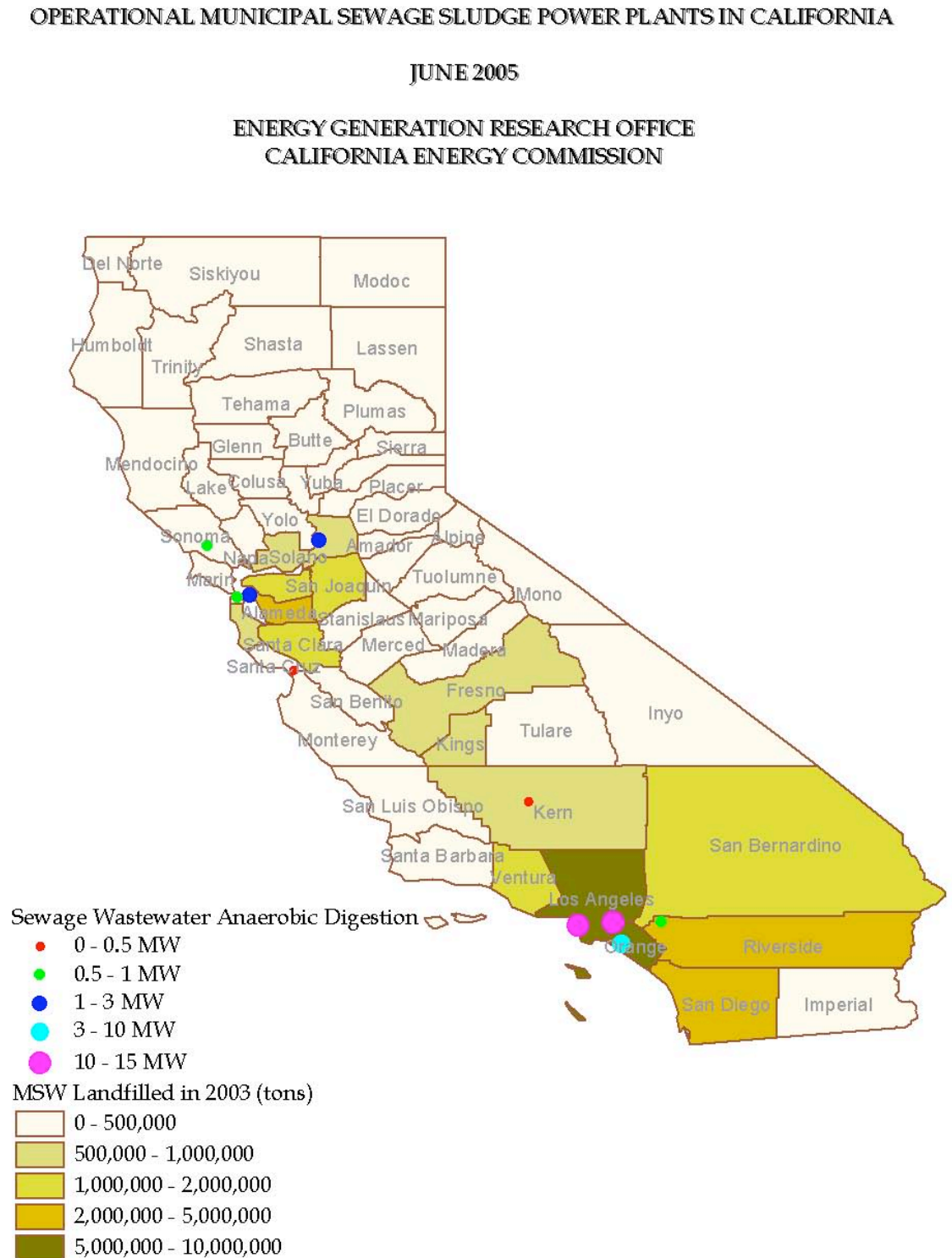
Barriers to Biomass Development

The California Biomass Collaborative summarized the barriers of biomass development in California as follows: [56]

The greatest barriers to biomass development are cost, policy, and public perception and acceptance; however, these barriers do not apply equally to each of the principal resource categories. All three are interrelated, and within each are technical, economic, environmental, and institutional constraints, all affecting infrastructure for energy and products development. The number and complexity of issues surrounding sustainable biomass management and use partly explain why, despite the many benefits of biomass industries in the state, no integrated state policy has so far been articulated or put in place to catalyze their development.[57] Barriers include:

> Cost Barriers
> - o Cost of fuel or feedstock and security and reliability of supply
> - o Cost of conversion
> - o Competition with vested utility, fuel, and waste management infrastructures
> - o Difficulty in obtaining long term contracts and power purchase agreements to secure financing
> - o Lack of predictable state and federal management programs
> - o Lack of stable long term economic and financial incentives and compensation for public benefits provided
>
> Policy
> - o Siting and permitting
> - o Uncertainties in environmental performance for new technologies
> - o Lack of coordination among jurisdictional agencies
> - o Utility interconnection for electric power generators
>
> Public perception
> - o Lack of public awareness and advocacy
> - o Limited training opportunities for skilled personnel needed for larger scale development

Cost

The sometimes high cost of biomass feedstock is a primary constraint to further biomass development in the state and even retention of the existing biomass industry. As demand increases, fuel costs for some types of biomass, particularly those from forestry and agriculture, will increase. Although fuel supply infrastructure has been developed in the state to support the existing industry, as new fuel or feedstock types are added and use increases additional infrastructure will be required including new harvesting, handling, and processing techniques

and equipment. Security of supply may also be an issue, as for the case of forest fuels in which wildfires may eliminate planned feedstock resources.

Once investments have been made, costs of power and fuels are not static and increase over time with inflation of labor, feedstock, maintenance, and administrative expenses. Contract prices and supplemental energy payments used to support the existing biomass power industry in the state are not currently escalated to account for inflation. Efficiency improvements can be made to some extent to offset the effect, but for facilities already operating at efficiencies above about percent, the rate at which cost of electricity declines is reduced relative to facilities operating at lower efficiencies. Shifts in technology to further increase efficiency will require concerted demonstration efforts and capital investment. Uncertainties in advanced technology performance and in long term policies and incentives make it difficult for the industry to identify financing for continued development of this sort.

Feedstock cost is not necessarily a primary issue with the use of municipal solid waste biomass. Tipping fees charged for waste disposal can offset the costs of fuel acquisition, reducing overall cost of power generation or other utilization. Instead, public perception and state policy serve to limit the use of waste for power generation in combustion power plants, the major existing alternative to landfilling. Public perception will continue to be an important factor in acceptance of other technologies as well.

Power contracts created following enactment of the federal Public Utilities Regulatory Policy Act (PURPA) of 1978, and the establishment of Standard Offer 4 for power generation in California, created the necessary economic conditions to stimulate the growth of the biomass power industry in the state. Long term contracts are critical for obtaining financing for new facility development or retrofitting and repowering existing facilities. For renewable power generation, long-term power purchase agreements (PPA) are available through the RPS for those winning bids in competitive solicitations. Projects that are not successful in the RPS process, but for which other benefits provide incentives for development, will also need long term contracts to secure financing. For power projects, the primary mechanism to obtain a PPA would be to qualify under PURPA and contract with a utility at the short run avoided cost (SRAC). The price paid for electricity is likely to be substantially below the price paid under the RPS, and differences in federal production tax credits further reduce incentives for biomass in comparison with other renewables. Contracts with municipal utilities would not allow supplemental energy payments from the Public Goods Charge fund. The lack of direct access in the state also limits the ability to recover generation costs. If biomass power projects are not competitive under RPS solicitations, securing long term contracts and financing may be difficult even if there are other significant benefits. This suggests both the need for policy which addresses other public benefits provided by biomass projects, as well as

possible alternative configurations and approaches by the industry that might lead to more competitive status within the RPS (such as combined heat and power (CHP) systems where feasible and strategically located facilities providing power and transmission benefits, especially if net metering is made more widely available).

Net metering is another economic incentive in renewable energy development. For biomass, net metering has been available only for biogas power systems and has not been applied equitably across all biomass generation technologies.[58] Legislation was enacted to establish the biogas pilot program because net metering was felt to facilitate implementation of energy efficiency programs to reduce energy consumption, reduce costs associated with energy demand, and reduce peak electricity demand. Loss of net metering would constitute a barrier to continued development of biogas systems. Extension of net metering to other biomass technology options would offer an economic incentive for other small and distributed systems. The application and compensation aspects of biomass net metering need further equity consideration among both the various biomass technologies as well as renewable energy systems in general, and in terms of the costs and benefits to customers and the public in general.

Biobased power, fuels, chemicals, and products in general must compete with mature industries that enjoy established fuel and feedstock supplies, technologies, markets, capital, and political influence at both the state and national levels. New technologies are often insufficiently developed or demonstrated and uncertainties exist regarding technical and environmental performance. Planning over the near term is hampered by a lack of credible data and uncertainty as to when new technologies will emerge, if at all. Technologies and products that have not been anticipated or fully evaluated by the current regulatory structure cannot always bear alone the cost of additional demonstration or testing. Developing adequate information can lead to delays in the permitting and project implementation needed to verify technology performance.

Few programs exist for training the necessary skilled personnel to work in an expanding biobased industry. With potential jobs numbering in the tens of thousands for a fully-expanded industry, education and training will become increasingly important. Universities and other schools do not generally have the financial resources or facilities needed to develop new programs to meet this need.

Policy

Fuel costs place biomass power generators at a disadvantage relative to wind and geothermal resources that do not use or pay for fuel. Production costs of biofuels are also higher than production costs for fossil fuels. Biopower is at

some disadvantage relative to combined-cycle natural gas-powered plants operating at substantially higher efficiency. Although the state is placing heavy emphasis on natural gas for new power generation, it has not yet adopted a policy addressing the sequestration of the resultant CO_2, as needed to meet environmental goals contained in state policy for sustainable development,[59] Greenhouse gas emissions are beginning to be addressed, however, through transportation policy, a climate change registry, and participation in developing REC trading markets. Based on the projected value of tradable carbon credits, adoption of such policies could result in incentives for power of $0.03/kWh or more.[60] Such a policy would still not provide specific incentives for biomass in competition with other, lower cost renewable technologies, as carbon credits would apply equally. Biomass, through photosynthesis, is the only renewable resource, however, that can be used directly to sink additional carbon from the atmosphere, if not permanently at least for long periods of time until renewable alternatives to fossil energy can be fully implemented. No state policy currently exists to encourage sequestering of this sort, although it is already accomplished to some degree by landfilling wastes and by fixed-carbon additions to soils from biomass growth, burning, and decay (the potential loss of soil carbon when soils are disturbed is an important consideration in the overall carbon balance for biomass). Biomass conversion can also avoid uncontrolled emissions of methane from decomposition, reducing the global warming potential of the carbon emitted prior to recycling through new biomass growth.[61] The lack of policy to credit the distinct sustainability benefits of biomass or to require sustainable use of natural gas and other fossil resources makes the cost of biomass appear high.

The ability of landfills to adjust tipping fees in competition with other industries may still lead to difficulties in introducing new technologies without more specific policies to limit waste disposal. However, policies concerning landfill will need to be developed with careful attention to technology improvements now being investigated including bioreactor landfills and the management of landfills to allow for landfill gas storage and the operation of peaking power plants. These developments may essentially move landfills into the category of conversion technologies. Permitting landfill gas-to-energy and other biogas facilities remains an issue due to air emissions (e.g. NO_x) from generating equipment even though other emissions are in some cases reduced (e.g., uncontrolled methane emissions). Concerns over NOx in most regions of the state may lead to increased use of flares without energy recovery due to lower emissions compared with internal combustion engines. Continued research, development, and demonstration, coupled with public education, will be critical to moving forward with improvements in waste management.

Permitting and siting processes are generally considered by technology developers to be complex, arduous, and sometimes unclear. Regulators and proponents have discussed streamlining these processes but no specific action has yet been taken. How or whether these processes can be streamlined while continuing to protect health and environmental quality is subject to debate.

Regulations attempting to define technologies and resources often create narrow or technically inaccurate definitions that inhibit application. Performance-based standards in general may prove more effective in achieving environmental objectives without inhibiting technical innovation.

Where access to the electric grid access is desired, utility interconnection can be difficult or expensive and uniform statewide standards have not yet been implemented. Interconnection costs can be high owing to standby charges and exit fees. Net metering is an important means of valuing the benefits of biomass and other renewables but is available only to certain types of biomass facilities. Current caps on the capacity allowed for net metering significantly limit expansion.

Lack of more comprehensive policies leads in some cases to unintended consequences. Legislation (SB 705, 2003) eliminating agricultural burning in the San Joaquin Valley, for example, was enacted in complement with legislation providing subsidies for the use of agricultural biomass in power plants (SB 704, 2003). The subsidies were of only short duration and have since expired. The legislation had unintended consequences for permitting new facilities that might be deployed to use the biomass. By eliminating open burning, agricultural burning emissions were no longer surplus and could not be counted as emission offsets required to obtain air permits for new sources. The lack of offsets constitutes a significant barrier to technology development and deployment. The state will need further policy or legislation to overcome the barrier if the original legislative intent was to encourage such technologies. Without allowable emission offsets, permitting of new facilities is not likely to occur.

Public perception

Resolving policy and regulatory issues will require good coordination among the various agencies involved, as well as increasing public awareness. This is especially true of conversion technologies to utilize solid wastes. Although modern solid-waste power plants are designed to and do meet air quality standards and are deployed elsewhere in the US and around the world, public concerns over incineration have effectively eliminated the technology from consideration in California. These concerns extend in part to other waste conversion processes. Without good demonstration of alternatives, public acceptance is likely to remain low. Other concerns are associated with the potential for conversion technologies to draw resources away from recycling operations, although energy conversion also serves to recycle biomass resources through new biomass production by photosynthesis.

Despite present prices, renewable energy should be considered a high value commodity along with other renewable biobased products from biomass, including recycled products. There are also concerns that the availability of good

conversion technologies will discourage the public from reducing waste generation. A similar argument might apply to recycling and other waste utilization. Public education and direct incentives aimed at reducing waste generation and disposal will be critical if total waste reduction is an objective. With both per-capita and total waste generation rates increasing, management alternatives of all types are urgently needed. No single alternative is likely to meet the objectives and needs of the state.

Information on the broad-based benefits of biopower, biofuels, biochemicals, and other biobased products is not widely disseminated in the general public, and as a result biomass industries have not so-far been assigned a central role in California's environmental and economic futures.

Performance Trends of Biomass Energy Conversion technologies

Existing and near-term planned biomass grid generating capacity in California in 2005 was about 1000 MWe including solid-fueled combustion power plants and engines, boilers, and turbines operating on landfill gas, sewage digester gas, and biogas from animal manures. Recent survey of existing facilities are indicated in Table 10 below. Total biomass capacity is about 2% of statewide peak power capacity

Net thermal conversion efficiencies for combustion power plants using biomass are in the range of about 20 to 28%, the higher values being associated mostly with facilities using circulating fluidized bed technologies. Advancements in integrated gasification combined cycle systems should enable efficiencies of 35% and above. Figure 16 shows overall efficiency versus net power output for several technology classes. The efficiencies shown are generally independent of fuel (liquid, solid, gas, fossil, or biomass). Also shown are efficiencies of the existing combustion biomass power plants (shown in blue and labeled 'California steam cycle biomass'), and several operating or planned commercial demonstrations (red dots labeled by company name or location).
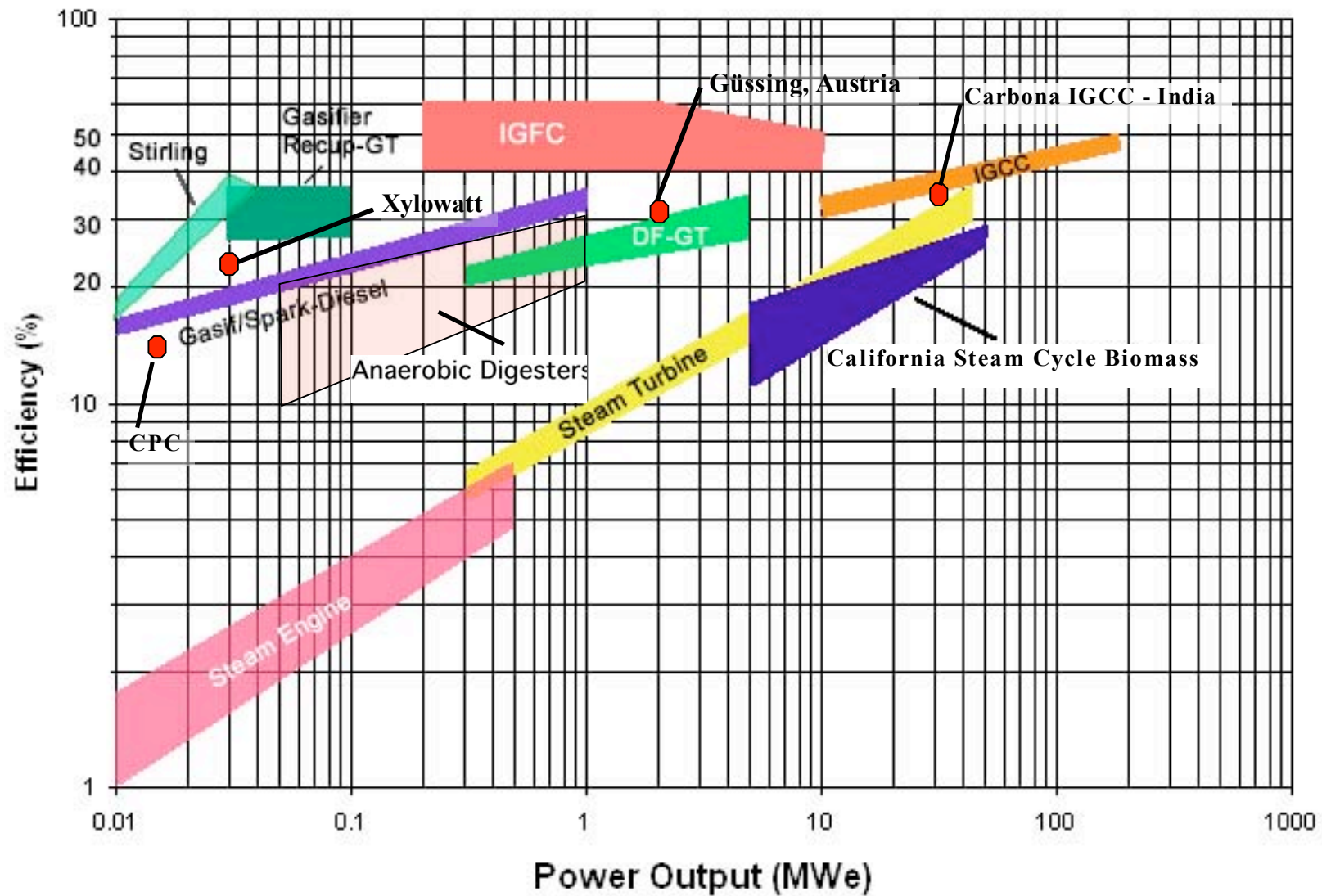
IGFC – Integrated Gasifier Fuel Cell   DF-GT – Direct Fired Gas Turbine (simple cycle)

IGCC Integrated Gasifier Combined Cycle

Bioconversion efficiencies depend on feedstock biodegradability and typically range from 13% to 22% when using newer, higher efficiency engines for generating electricity from biogas. Gas scrubbing and catalytic emission control devices added to comply with new air emission standards may cause net efficiencies to decline.

Average efficiency in the future will depend on the mix of small or distributed and larger, centralized facilities. To capture benefits associated with voltage support for the local electricity grid, reduced power transmission, decreased transportation, and better potential for waste heat utilization in combined heat and power (CHP) applications, smaller, distributed generation systems may be deployed. These systems will likely have lower electrical conversion efficiencies compared to larger centralized facilities, but overall efficiencies when CHP is included will typically be higher than power-only designs.

Table 10. Summary of technical performance biomass facilities[62]

Type of facility	Direct Combustion	Landfill gas to energy	Wastewater treatment plant	Animal & food waste digesters	Total
Number of facilities	32	59	115	23	229
Number of facilities operating	32	59	For verification	7	
Total gross generating capacity—existing and planned (MWe)	760.9	257.6	63 (from 18 plants)	5.6	1,087.1
Total net (to grid) generating capacity (MW)	641.5	227.2	0.96 (from 2 plants	For verification	869.6
Annualized capacity factor (%)	46-100 (ave = 77)	93-97 (ave = 94)	55-97 (ave = 70)	99 (from 1 facility)	81.1[b]
Availability (%)	76-98 (ave = 93)	23-98 (ave = 80)	64-100 (ave = 84)	96 (from 3 facilities)	89.2[b]
Gross efficiency (%)	25-30.1 (ave = 28)	28-36 (ave = 34)	23-32 (ave = 29)	na*	30.4[b]
Net efficiency (%)	22-26.7 (ave = 24)	26-33 (ave = 30)	21-28 (ave = 26)	55[a] (from 1 facility)	26.0[b]
Estimated annual gross energy production (GWh)	5,665	1,918	475 (from 18 plants)	41.6	8,099.6
Estimated annual net energy production (GWh)	4,776	1,692	7.2 (from 2 plants)	na*	6,475.2

* na = not available

[a]Reported high efficiencies were from combined heat power (CHP) facilities; data on electrical efficiencies as separate from CHP are not available from these facilities.

[b]Calculated as capacity weighted average.

Biomass acquisition costs and resource supply

One of the primary constraints facing the increasing utilization of biomass is the cost of fuel or feedstock acquisition. Technical resource estimates do not specifically incorporate economic factors although in reality they are cost sensitive. Forest biomass on steep terrains excluded from the technical resource estimates might, for example, be harvested at high cost as long as erosion control and other compensating measures deployed at great expense accomplished equal ecosystem or resource management

objectives. There would be little economic merit to such activity for the purposes of biomass utilization. Estimates of the statewide economic resource potential can be derived from general cost assumptions, but improved estimates require additional detailed assessments.

The optimal use of biomass implies a system integration that accounts for production, handling, conversion, product marketing, and environmental management over the full life cycle. For this reason, the economic feasibility is feedstock-, product-, and site-dependent. Exclusive of harvesting and downstream processing operations, production costs for agricultural and other biomass residues are typically allocated to the primary crop production system and not separately accounted. In contrast, dedicated crops grown for biomass assume full allocation of production costs, but may contribute other high value benefits, such as soil remediation, that can be used to offset high costs of production. Production costs for dedicated crops are quite variable and depend on species, production site, level of management, and resulting yield.

Biomass already collected at a potential site of use, such as certain food processing wastes, sawmill residues, and municipal wastes at transfer and material recovery facilities may be available at little or no additional cost. Facilities using these feedstocks do not incur additional collection and transportation costs, although there are typically still expenses for handling, processing, and storage. Tipping fees are charged at most landfills and waste-to-energy facilities and are an important source of revenue. Continuing development of waste conversion processes could lead to greater resource competition and changes in tipping fees. Longer term supply contracting is an advantage for most facilities in securing financing and ensuring reliable operation.

Collection costs for agricultural crop residues depend on the type of crop, yields, harvesting equipment, labor, in-field drying and other processing, harvesting losses, and nutrient export, the latter representing the nutrients taken off the field in the biomass that otherwise would have been retained and reincorporated into the soil. If not returned in the form of ash, sludge, or compost, nutrients will need to be replaced for the cropping system to be sustainable. Animal manure collection and handling costs are low for dairies where anaerobic digesters are integrated into on-farm waste management operations, but high for pastured animals. In the latter case, manure collection is generally considered infeasible.

Transportation costs may limit the size of facilities using more distributed biomass resources such as crop residues, dedicated crops, forest thinnings, and logging slash. The combination of increasing feedstock delivery costs offset by generally declining capital, operating, and product-marketing costs as the facility size increases can lead to an optimum facility size. Where collection and other feedstock acquisition costs are low or offset by tipping fees, such as in the case of urban wood fuels separated from municipal waste, longer transport distances are economically feasible. Due to the low

density of some forms of biomass, especially straw bales, truck payload is frequently limited by volume and trucks do not carry the full weight allowed. In order to increase payload, the biomass can be densified, such as by making pellets. The cost of densification must be offset by reduced transportation costs, and is generally justified only for long hauls. However, densification may have other advantages in material handling and conversion, so transportation may not be the only determining factor. Densification is not used currently in the fuel supply infrastructure for existing biomass power plants. Bulk densities of wood chips are sufficiently high that trucks mostly operate near their weight limits.

Most facilities using biomass require storage due to the seasonal feedstock production characteristics and to enhance reliability in the case of feedstock supply disruptions. Grains are commonly harvested during the summer and fall, whereas orchards are pruned in the winter and spring. Harvest windows may be quite short. Rice straw, for example, can typically be collected dry only during a six- to eight-week period during the fall. Equipment access to the field following the first rains is often restricted and reentry is generally possible only in the spring after the fields have dried. The process of over-wintering rice straw in the field is actually beneficial in leaching potassium and chlorine to improve combustion properties and recycle nutrient to the field,[63] but unpredictable weather patterns lead to uncertainties in planning and risks for field preparation and planting in the spring.[64]

Orchard removals that supply a large fraction of current agricultural fuel used by the state's biomass power sector occur throughout the year. The composition of MSW, including the fraction of green waste, fluctuates according to season, and much of food processing waste is highly seasonally dependent. Equipment access to forest lands can be limited by weather conditions both during winter and under extreme fire conditions during the summer. Wood and woody materials are mostly stored uncovered in piles or windrows. Herbaceous materials such as baled straw generally require covered storage over winter to reduce losses. Storage under permanent cover, such as in metal barns, tends to be of lower overall cost due to reduced losses compared with tarps and other more temporary shelter,[65] but system selection is scale specific.

Impact of fuel cost on cost of energy

Feedstock-cost per unit product-output depends on the conversion process efficiency. Fuel contributions to the cost of electricity (COE) for existing solid-fueled biomass power plants purchasing fuel at $20 to 40/dry ton are in the range of $0.02 to 0.05/kWh (Figure 17). The impact of conversion efficiency on COE is a primary driver for research into advanced conversion systems. As noted earlier, at 20% efficiency, each $1/dry ton increment in the cost of fuel increases COE by roughly $0.001/kWh. For comparison, each $10/ton increment in the cost of feedstock to an ethanol production facility adds between $0.07 and 0.14/gallon to the cost of ethanol. Research and development efforts are targeting total production costs below $1.00/gallon, therefore maintaining high conversion efficiency and low feedstock cost are critical.

Figure 17. Impact of conversion efficiency on the fuel cost contribution to cost of electricity (COE) from biomass[66]
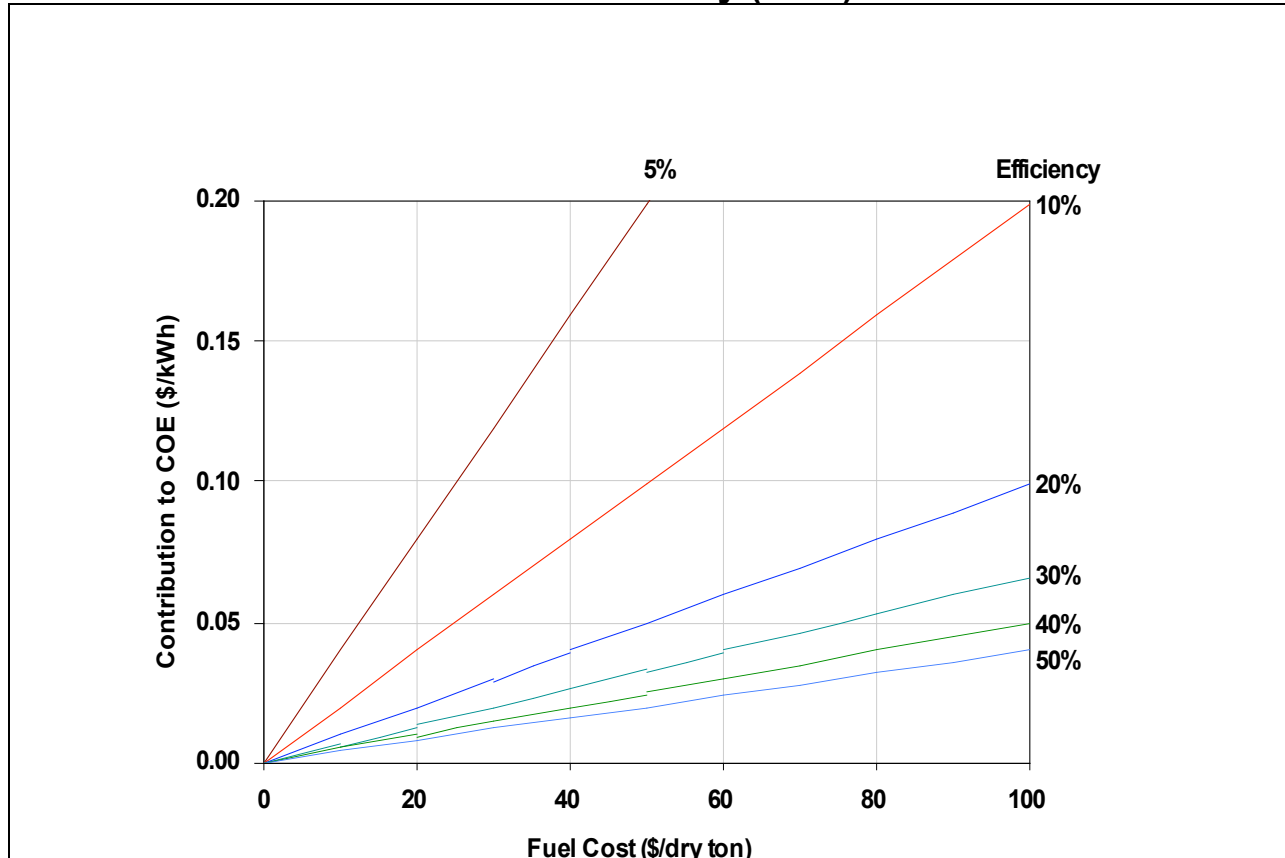
Cumulative resource supply costs

Overall, an estimated 34 million tons of the current technical resource might be obtained at average costs below about $40/dry ton including short-haul transportation but excluding storage and processing (Figure 18). Beyond this value, costs begin to increase sharply. This does not mean that the existing solid-fueled biomass industry, using approximately 5 million BDT/y, is able to procure fuel at low cost. Each fuel type has an associated collection cost that can be allocated to the utilization activity. For any single facility, fuel cost might range from zero to $40/BDT or higher depending on the resource available. The average fuel costs of $22 to $40/BDT for the solid-fuel direct combustion sector mentioned earlier are based on an assortment of fuels ranging from sawmill residues to forest thinnings. An example for a single facility using forest thinnings was analyzed through a detailed geographic information system (GIS) model for Plumas County showing how cost varies within a specific fuel class as a function of amount delivered (Figure 19).[67]

Total feedstock expense to supply the statewide technical resource estimate of 34 million dry tons would exceed $950 million (Figure 20). Landfill gas and biogas from sewage treatment are not considered in this analysis. The resource supply ranking is based on a least cost sorting across all categories of biomass and is only useful for the purposes of estimating the total statewide potential costs.

Figure 18. Estimated overall statewide biomass resource cost curve, 2005 technical resource base (excludes storage and on-site processing and handling costs)[68].
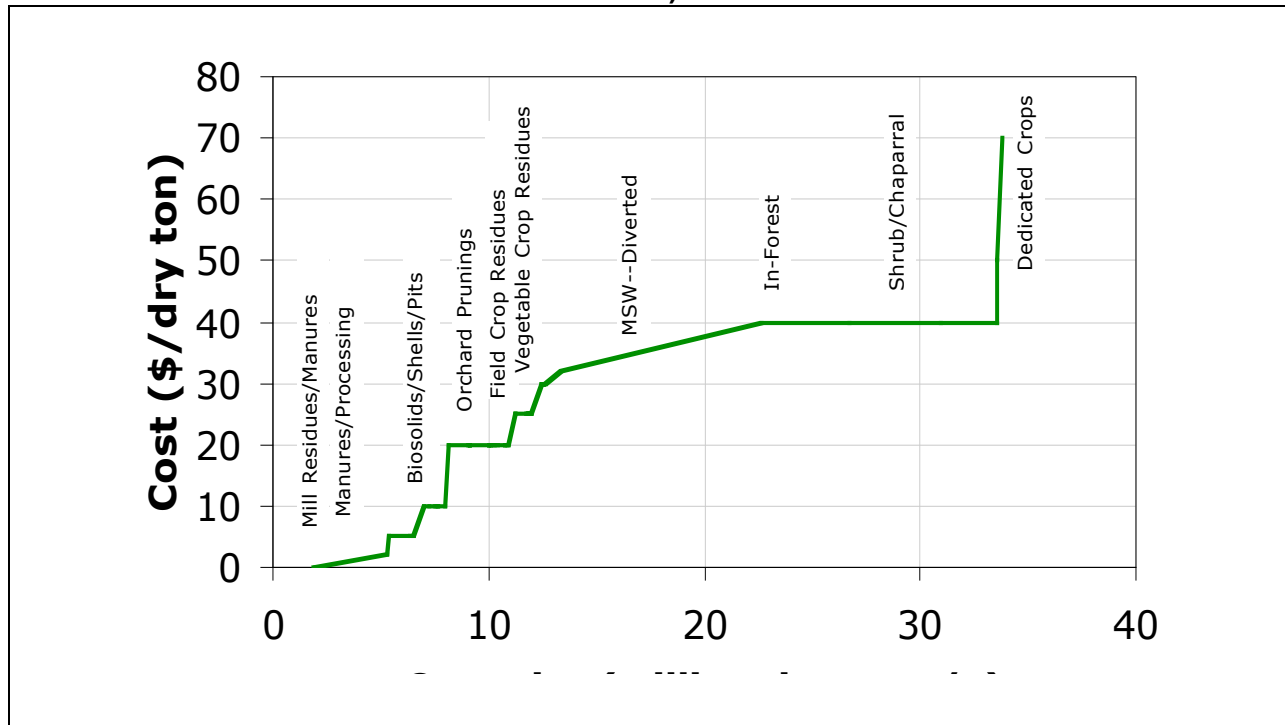
Figure 19. In-forest thinnings biomass resource cost curve for a single site location in California.[69]
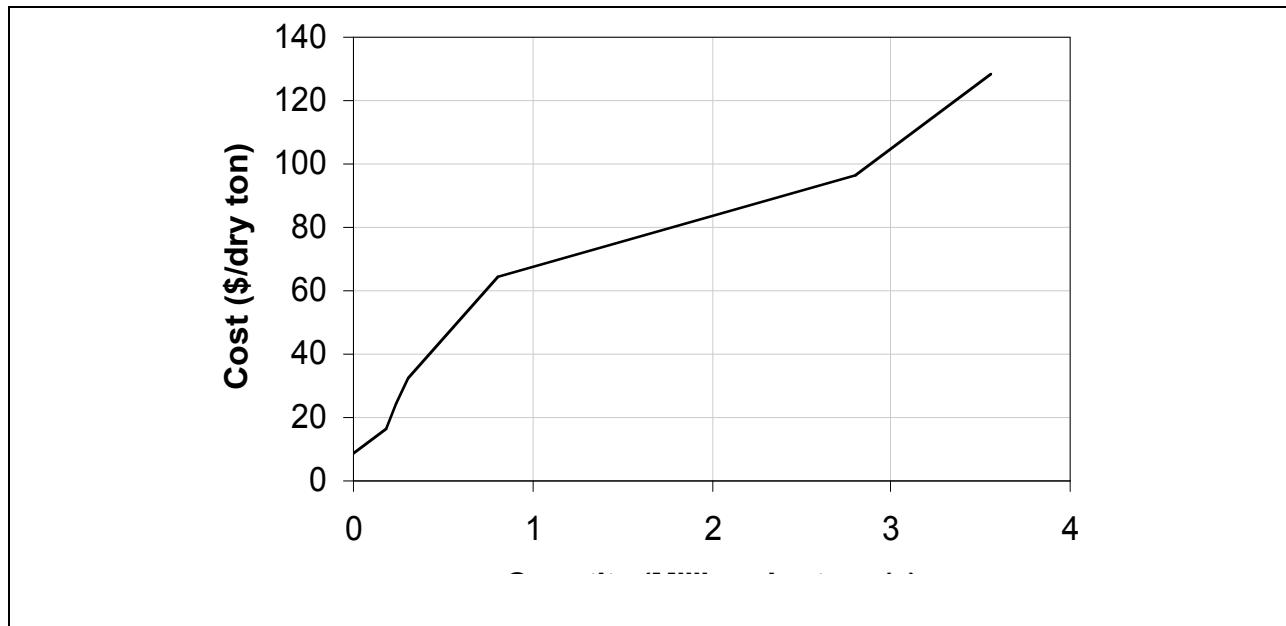
Figure 20. Cumulative estimated least-cost statewide feedstock costs, 2005 technical resource base.[70]
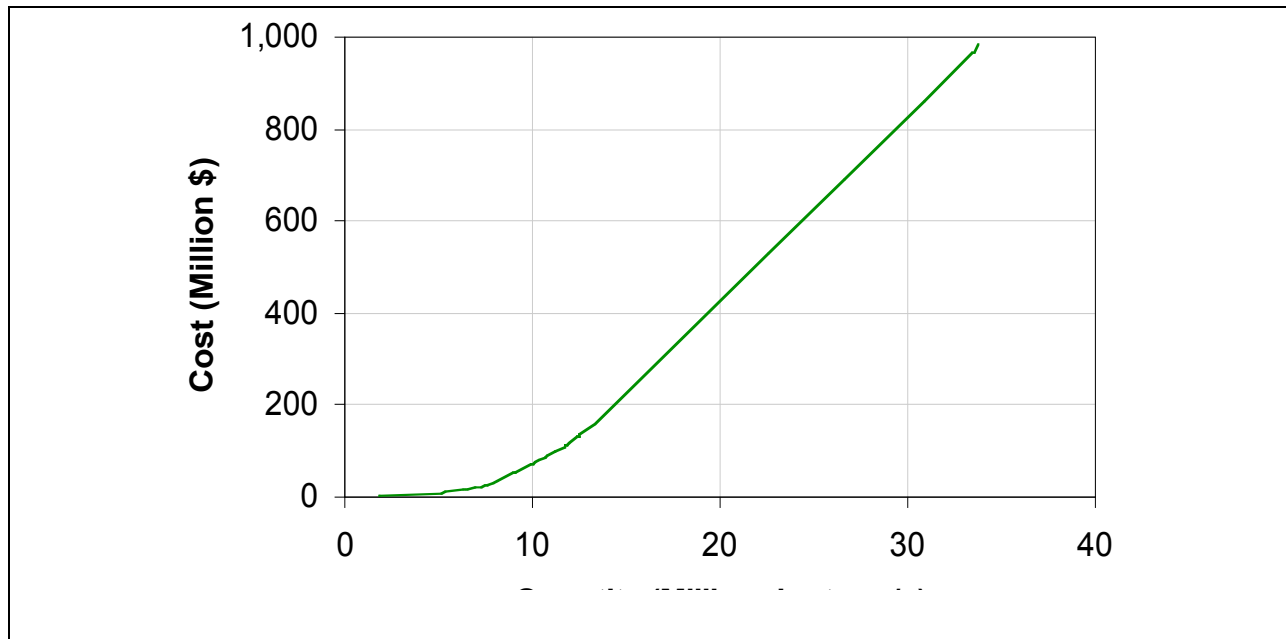
Levelized Cost of Electricity Production

Table 11 shows the summary results of the LCOEs of all the biomass plants. LCOEs were calculated from 2005 to 2017 in both constant and current dollars. The resulting LCOE's of each chosen technology were compared to combined cycle. In using current dollar analysis, the wholesale price of electricity using the 2003 Energy Commission forecast and E3 – CPUC forecast and LCOE of combined cycle in current dollar were used for comparison. Similarly, using constant dollar analysis the LCOE's of each technology were compared to LCOE of combined cycle in constant dollar.

Table 11. Summary of LCOEs in both 2004 constant dollars and current dollars for fluidized bed, stoker boiler, landfill gas, dairy waste, and wastewater[71]

25 MW Fluidized bed

Biomass Fluidized Bed Combustor			
	LCOE ($/kWh)	2004 Constant $	
Year	No PTC-con	PTC - con	Combined Cycle-con
2005	0.0698	0.0663	
2006			0.0656
2007	0.0679	0.0644	
2010	0.0580	0.0544	0.0629
2017	0.0522	0.0487	0.0639

		LCOE ($/kWh) Current $		
Year	No PTC - cur	PTC - cur	Wholesale CEC 2003 Forecast	Wholesale E3 CPUC Forecast	Combined Cycle-cur
2005	0.0863	0.0819	0.0316		
2006				0.0674	0.0693
2007	0.0839	0.0796			
2010	0.0716	0.0673	0.0426	0.063	0.0742
2017	0.0645	0.0602	0.0587	0.0716	0.0915

25 MW Stoker boiler

Year	LCOE ($/kWh) No PTC-con	2004 Constant $ PTC-con	Combined Cycle-con
2005	0.0621	0.0586	
2006			0.0656
2007	0.0609	0.0574	
2010	0.0524	0.0489	0.0629
2017	0.0468	0.0433	0.0639

Year	Current $ No PTC-cur	PTC-cur	Wholesale CEC 2003 Forecast	Wholesale E3 CPUC Forecast	Combined Cycle-cur
2005	0.0768	0.0724	0.0316		
2006				0.0674	0.0693
2007	0.0753	0.0709			
2010	0.0648	0.0604	0.0426	0.0630	0.0742
2017	0.0579	0.0535	0.0587	0.0716	0.0915

25 MW Gasifier (BIGCC)

25 MW gasifier	LCOE $/kWh (2004 constant $)		
Year	no PTC-con	PTC-con	Combined Cycle-con
2005	0.0823	0.0787	
2006			0.06563
2010	0.0674	0.0639	0.0629
2017	0.0628	0.0593	0.0639

Year	no PTC-cur	PTC-cur	Wholesale CEC 2003 Forecast	Wholesale E3 CPUC Forecast	Combined Cycle-cur
2005	0.1017	0.0973	0.0316		
2006				0.0674	0.0693
2010	0.0833	0.0790	0.0426	0.063	0.0742
2017	0.0776	0.0733	0.0587	0.0716	0.0915

1 MW Landfill

Landfill Gas 1 MW			
LCOE $/kWh 2004 constant $			
Year	no PTC-con	PTC-con	Combined Cycle-con
2005	0.0334	0.0299	
2006			0.06563
2010	0.0296	0.0261	0.0629
2017	0.0276	0.0241	0.0639

Current $					
Year	no PTC-cur	PTC-cur	Wholesale CEC 2003 Forecast	Wholesale E3 CPUC Forecast	Combined Cycle-cur
2005	0.0413	0.0369	0.0316		
2006				0.0674	0.0693
2010	0.0366	0.0323	0.0426	0.063	0.0742
2017	0.0342	0.0298	0.0587	0.0716	0.0915

Dairy waste

LCOE - 200 kW Dairy Waste to Biogas/Power Generation

2004 Constant $

With sales of heat & sludge/fertilizer

Year	no PTC -con	PTC - con	Combined Cycle-con
2005	0.0430	0.0394	
2006			0.06563
2010	0.0339	0.0304	0.0629
2017	0.0208	0.0173	0.0639

Current$

Year	no PTC - cur	PTC - cur	Wholesale CEC 2003 Forecast	Wholesale E3 CPUC Forecast	Combined Cycle-cur
2005	0.0531	0.0487	0.0316		
2006				0.0674	0.0693
2010	0.0419	0.0376	0.0426	0.0630	0.0742
2017	0.0257	0.0214	0.0587	0.0716	0.0915

Wastewater

LCOE - 1000kW Wastewater to Biogas/Power Generation

2004 Constant $

Without sales of heat & sludge/fertilizer

Year	no PTC - con	PTC - con	Combined Cycle-con
2005	0.0406	0.0371	
2006			0.06563
2010	0.0375	0.0339	0.0629
2017	0.0342	0.0307	0.0639

Current $

Year	no PTC - cur	PTC - cur	Wholesale CEC 2003 Forecast	Wholesale E3 CPUC Forecast	Combined Cycle-cur
2005	0.0502	0.0458	0.0316		
2006				0.0674	0.0693
2010	0.0463	0.0419	0.0426	0.0630	0.0742
2017	0.0423	0.0379	0.0587	0.0716	0.0915

Fluidized bed

The estimated base case (as-in service 2005) capital cost for a new solid-fueled 25 MWnet fluidized bed combustor is about $2,800/kW (See Table 1). Using the assumptions, the calculated LCOE's with PTC is about $0.066/kWh and $0.0698/kWh without PTC (at 2004 constant $). These LCOE's assumed 20% net efficiencies, and $22 per ton fuel cost, 16% return on equity at 33% equity ratio.

Sensitivity curves of pertinent economic parameters are shown in Figure 21. In this figure, a steeper curve through the base case point implies a higher sensitivity of LCOE to the parameter represented by the curve. LCOE is sensitive to capacity factor, efficiency, fuel cost and cost of equity (rate of return on equity). A 30% decrease in capital cost decreases LCOE from $0.07/kWh to about $0.06/kWh and a $10 per ton increase in fuel cost adds approximately $0.01/kWh. Complete elimination (-100% change) of capital charges reduces LCOE to about $0.033/kWh (2004 constant dollars). At zero cost fuel, LCOE decreases to $0.049/kWh. LCOE increases more rapidly as the

conversion efficiency declines below base case efficiency of 20% and as efficiency increases there is less impact on LCOE.

Figure 21. Sensitivity of LCOE (2004 constant $/kWh) for a 25 MW fluidized bed combustor at base case assumptions without PTC.
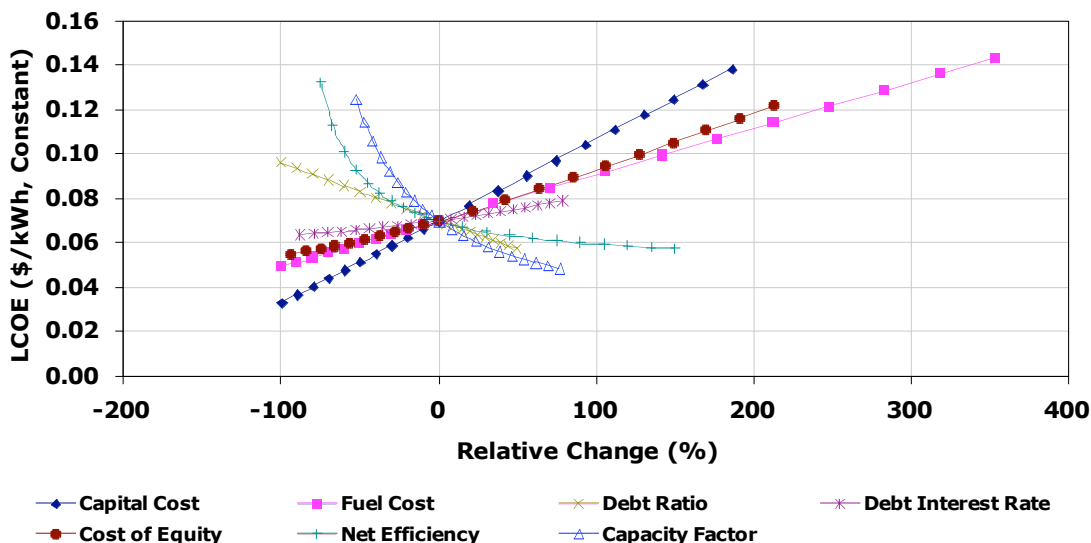
Figure 22. Comparison of fluidized bed LCOEs in current dollars
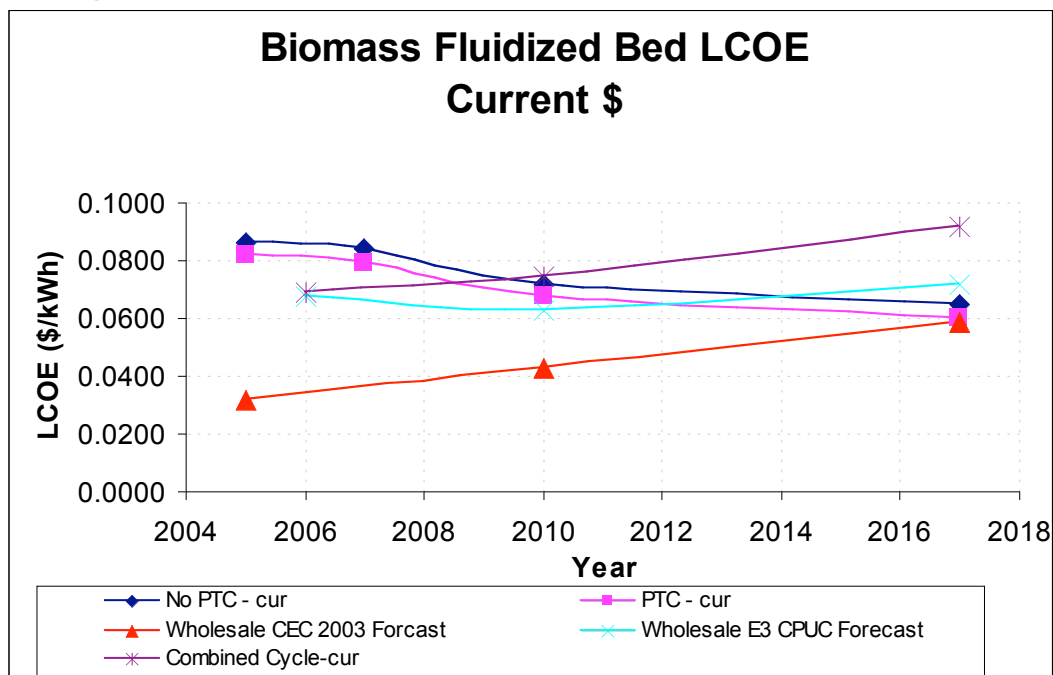
Table 11 and Figure 22, indicate the comparison of LCOE's of biomass plants to convention combined cycle facility in both current and constant dollars (2004$). In Figure 11, installation of fluidized bed could be cost competitive beyond 2009 when compared to combined cycle facility. While using E3 CPUC wholesale price, fluidized bed combustor could be cost competitive beyond 2012, and using the 2003 Energy Commission wholesale price forecast, biomass combustor could be cost competitive beyond 2017. A more detail analysis on this comparison is discussed in the economic potential section below.

Stoker Boiler – Levelized Cost of Electricity

Installation of a new stoker boiler combustor with the above mentioned assumptions yields to calculated base case LCOE's of $0.059/kWh with PTC and $0.062/kWh without PTC. Similar to fluidized bed combustor, LCOE of stoker boiler is particularly sensitive to capital cost, capacity factor, return on equity and fuel cost . Without debt charges (-100% change), LCOE decreases to a minimum around $0.03/kWh. Without fuel cost, LCOE is about $0.04/kWh.

LCOE's of new biomass gasification combined cycle with and without PTC are $0.079/kWh and $0.082/kWh, respectively. Base case capital cost (in 2005) is $2800/kW. Included in the base case assumptions are capacity factor of 90% and electrical efficiency of 34%.

Table 11 shows that its cost competitive to install landfill gas, dairy waste and wastewater biogas generation facilities in all years.

Landfill gas to energy facilities generate base case LCOE's of $0.030/kWh with PTC and $.033/kWh without PTC (2005 base case, 2004 constant $).

Anaerobic digestion of dairy wastes facilities typically generate at LCOE of $0.039/kWh with PTC and $0.043/kWh without PTC (2005 base case, 2004 constant $).

Power Generation Potentials

2005 Potential Power Generation from Biomass

Table 12 shows the biomass resources and power generation potentials for 2005 resource base. The gross biomass resource in the state, were it all to be used for power generation using the thermochemical and biochemical energy conversion technologies

described above, would be sufficient to generate in excess of 10,700 MW_e of electricity. About 2,100 MW_e of this could come from agricultural biomass, 3,600 MW_e from forestry, and 5,000 MW_e from municipal wastes including landfill and sewage digester gas. Not all of the resource can, should, or will be used for power, and the technical potential is estimated to be substantially less at close to 4,700 MW_e, sufficient to generate 35,000 GWh of electrical energy. The existing and planned capacity of all the biomass facilities is about 969 MW, thus, the net technical potential for further development is about 3684 MW with 3684 MW possible use via thermal conversion and 657 MW via biochemical conversion. If we are to maintain current share (20%) of renewable net system power for this 2005 data, average additions to the state's generating capacity of 50 MW_e per year would be needed under the present RPS, and 85 MW_e per year under an accelerated plan yielding 33% renewable electricity by 2020.

A more detail analysis using a strategic value analysis approach for 2010 and 2017 are presented below.

Table 12. Estimated electricity generating potential from biomass in California, 2005 resource base[72]

	Potential MWe		Potential GWh		Existing/Planned MWe GWh		Net Technical MWe GWh	
	Gross	Technical	Gross	Technical	MWe	GWh	MWe	GWh
Total Biomass	**10,711**	**4,654**	**79,757**	**34,650**	**969**	**7,216**	**3,684**	**27,434**
Possible Use by Thermal Conversion	8,536	3,671	63,561	27,337	644	4,796	3,027	22,541
Possible Use by Biochemical Conversion	2,175	982	16,196	7,313	325	2,420	657	4,893
Total Agricultural	**2,144**	**1,021**	**15,964**	**7,605**	**141**	**1,051**	**880**	**6,554**
Total Animal Manure	986	389	7,339	2,893	4	30	385	2,863
Total Cattle Manure	612	224	4,555	1,669	4	30	220	1,639
Milk Cow Manure	285	142	2,119	1,060	4	30	138	1,030
Total Orchard and Vine	346	242	2,573	1,801	93	694	149	1,108
Total Field and Seed	575	281	4,281	2,092			281	2,092
Total Vegetable	112	9	835	70			9	70
Total Food Processing	126	101	936	749	44	328	57	421
Total Forestry	**3,628**	**1,934**	**27,013**	**14,404**	**268**	**1,996**	**1,666**	**12,408**
Mill Residue	839	451	6,244	3,355				
Logging Slash	1,079	575	8,035	4,285				
Forest Thinning	1,088	583	8,103	4,345				
Shrub	622	325	4,631	2,419				
Total Municipal	**4,940**	**1,698**	**36,780**	**12,641**	**560**	**4,170**	**1,138**	**8,472**
Biosolids Landfilled	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Biosolids Diverted	61	49	454	363			49	363
Total MSW Biomass Landfilled	1,926	(1)	14,340	(1)	(1)	(1)	(1)	(1)
Total MSW Biomass Diverted	2,142	1,071	15,952	7,976	239	1,780	832	6,197
Landfill Gas (LFGTE)	694	500	5,171	3,724	258	1,921	242	1,803
Biogas from waste-water treatment plants	116	78	863	578	63	469	15	109

(1) Included in LFGTE.

Totals may not add due to rounding.

2010 and 2017 Power Generation Potentials

With improved conversion efficiencies and growth in biomass resources, the state's gross annual biomass production might be sufficient to support a technical potential incremental generation of 5,200 MW and 7,100 MW_e by 2010 and 2017, respectively. Without improving generating efficiencies, incremental potential in 2017 would be closer to 4,800 MW_e by 2017. Electrical energy contributions could reach 60,000 GWh by 2017 or 18% of projected statewide consumption of 334,000 GWh, although generation is unlikely to reach this level without significant additional development support and clear market signals, such as long term contracting opportunities. These projections are therefore likely optimistic.

Figure 23 illustrates existing/planned, technical and gross generating capacities. Existing and planned category does not show growth thus a significant opportunity exists to plan and install biomass energy generation units to exploit available already available wastes. 2017 is the target date for the RPS to achieve 20 percent of generating capacity from renewables including biomass. Biomass currently accounts for 20 percent of gross renewable generation in California.[73] To maintain this level through 2017, on average 50 MWe with a capacity factor of 85 percent must be installed annually. It is estimated that 1/3 of the increased biomass electrical generation can come from installations on existing landfill and water treatment plants.

Figure 23. Projected potential electric generating capacity from biomass[74]
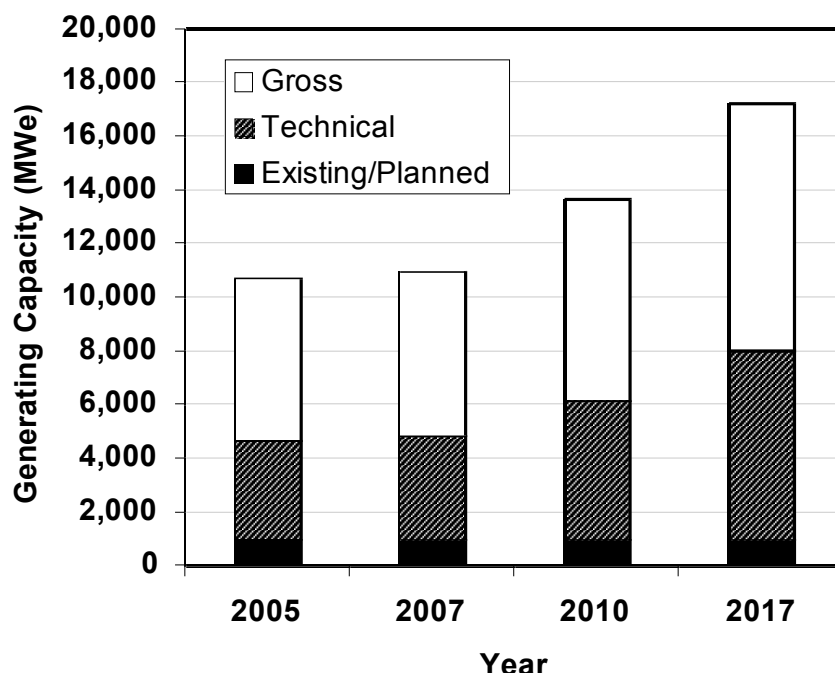
YEARS 2010 AND 2017 ECONOMIC POTENTIAL

FIRE THREAT FOREST FUELS

The economic potentials for 2010 and 2017 were investigated for high fire threat forestry areas. The results presented here are based on the 2010 and 2017 summer peak conditions. Two kinds of forestry fuels were investigated: (1) the first investigates installing generation within high fire threat forestry areas. Although there are many areas in California that is susceptible to forest fires, the study was limited to areas that had a minimum of 120,000 Bones-Dry-Tons (BDT) of wood material. (2) The second area investigates the burning of wood waste from logging operations or forest slash. Since slash is also located within the high forest threat areas, the impact of slash is an incremental increase in the total amount of generation that could be installed in the area.

The objective of analyzing this fire threat fuels is to determine if biomass power plants could be installed at specific locations that could simultaneously burn wood waste, reduce fire threats and improve transmission reliability. If transmission benefits could be found in the highest fire threat areas that usually have small transmission and

subtransmission lines and low loads, then the methodology could be applied to other areas as well.

The analysis did not take into consideration whether the local roads are adequate for hauling wood waste. It also did not include any analysis on emissions, water availability, land contours or anything of that nature. The goal was to develop a methodology for locating generation that provides benefits to California.

CDF calculated the amount of forest biomass that could be recovered from the thinning of forests and logging waste. The BDT and MW equivalents were based on the amount of forest fuels that could be transported within a 25 mile radius circle of each substation. From this data, DPC selected the substations to install biomass power generation.

Simulations were developed to study the amount of biomass generation that could be integrated onto the system. The transmission contingency overloads (AMWCO – Aggregated Megawatt Contingency Overload) of the system were monitored as incremental amounts of biomass generation were installed.

The contingency analysis simulation which in this case is called first contingency (N-1), as defined by the Western System Power Pool (WSPP) and the Northern Electric Reliability Council (NERC) was simulated after the transmission lines, buses, and biomass generation was installed. During each simulation, one transmission line or one generator is removed temporarily from the data set and a power flow simulation is completed. The number of violations and magnitude of overloads are calculated and compared to the base case. DPC completed power flow model simulations consisting of more than 5000 contingencies. The contingency analysis used the thermal limit B for the lines and transformers and the post contingency state for each contingency was obtained using full AC power flow solutions.

POWER FLOW RESULTS FOR FIRE THREAT FOREST FUELS

Sixteen counties were selected in the analysis. These counties had BDTs of 120,000 or higher. The counties and their respective generation potential are shown below.

Table 13. Counties Selected for Forest Fuels[75]

County	2010 Potential Generation (MW)	County	2010 Potential Generation (MW)
BUTTE	14.11	SHASTA	45.47
CALAVERAS	10.43	SISKIYOU	24.37
EL DORADO	19.52	SONOMA	17.15
HUMBOLDT	46.77	TEHAMA	16.61
LAKE	13.50	TRINITY	32.14
MENDOCINO	40.67	TUOLUMNE	10.23
NEVADA	12.04	YUBA	7.29
PLACER	7.95	Total	**336**
Plumas	17.58		

Several power flow simulations were completed for this analysis. A power flow of the 2010 Summer Peak base case was completed as a benchmark of the current status of the California transmission system. This base case simulation produces a base AMWCO (Aggregated Megawatt Contingency Overload) value which would be used to compare to the biomass alternatives. Since the majority of the FTTA (Fire Threat Treatment Areas) were located in Northern and Central California, the simulation modeled the PG&E transmission area only. Table 14 shows the results of the 2010 summer base case.

Table 14. 2010 Summer Base Case Results[76]

2010 Summer Base Case	
Contingencies:	251
Violations:	424
AMWCO:	11,347 MW

The first biomass simulation modeled the FTTA forest and shrub in the 16 counties selected for study. There was a total of 336 MW of potential biomass generation that could be developed in these counties. However, in selecting the

25 mile radius circles associated with wood waste transporting, it was discovered that only 13 substations could be located within the 16 counties without creating major overlaps. The projected generation was reduced to 236 MW. DPC could only capture 70 percent of the potential generation. Table 15 lists the 13 substations.

Table 15. Substations Selected for FTTA Generation[77]

Buss Information			Annual MW per Bus 25 mile Radius		
WECC	Name	County	FTTA Forest	FTTA Shrub	Total
31091	RDGE CBN	HUMBOLDT	27.04	0.04	27.08
31118	KEKAWAKA	TRINITY	24.25	0.13	24.38
31227	HGHLNDJ2	LAKE	12.36	4.08	16.45
31306	WILLITS	MENDOCINO	22.53	0.84	23.37
31360	MIRABEL	SONOMA	14.81	0.81	15.61
31452	TRINITY	TRINITY	16.32	0.40	16.72
31590	CEDR CRK	SHASTA	23.38	1.45	24.83
31610	TYLER	TEHAMA	9.87	0.08	9.94
31674	BIG MDWS	PLUMAS	13.24	0.18	13.42
32364	GRSS VLY	NEVADA	24.04	0.61	24.65
33926	CH.STNJT	TUOLUMNE	12.90	2.80	15.70
37110	JONESFRK	EL DORADO	9.38	0.57	9.95
38290	PARADISE	BUTTE	12.80	0.30	13.10
Total			222.91	12.29	235.20

Prior to running the contingency analysis, three 60 kV transmission lines were reconductored. The 18 MVA line rating was too low and was doubled to 36 MVA. This upgrade proved to be beneficial in the system analysis. Table 16 shows the results of having 236 MW of biomass installed in 13 locations and 3-60 kV lines reconductored.

Table 16. 2010 Summer Biomass Case Results – 236 MW[78]

2010 Summer Case /w 236 MW	
Contingencies:	244
Violations:	400
AMWCO:	10,077 MW
AMWCO Impact:	- 1,270 MW
Benefit Ratio:	- 5.38

The addition of 236 MW into the system at these locations proved to be very beneficial. The 10,077 MW of AMWCO decreased the base AMWCO value by 1,270 MW. The benefit ratio of this impact was -5.38 MW. Signifying that for ever 1 MW of biomass installed reduces the total overloads by 5.38 MW.

In the second analysis, DPC incorporated the biomass generation that was associated with burning the slash. Harvest slash is wood waste from logging operations. If the slash was recovered around the 25 mile radius of the substations listed in Table 15, then the total generation could be increased to 393 MW. Table 17 shows the results of the additional biomass generation.

Table 17. 2010 Summer Biomass Case Results – 393 MW[79]

2010 Summer Case /w 393 MW	
Contingencies:	241
Violations:	404
AMWCO:	10,138 MW
AMWCO Impact:	- 1,209 MW
Benefit Ratio:	- 3.07

When compared to the 2010 Summer base case, there is an AMWCO impact difference of 1,209 MW. This leads to a total benefit ratio of -3.07 MW. Although this is lower than the previous simulation that only had FTTA, a negative effect of -3.07 MW to 1 MW is very acceptable and reduces the system overloads.

The lower Benefit Ratio in the second analysis was due to two situations. The first is an increase in the number of overloaded lines as the generation is

increased on the small conductors on the transmission lines. More reconductoring would need to be completed or other substations selected near larger transmission lines. The second is the instability of the system. Even at these low and dispersed generation levels, DPC discovered that installing generation at these remote sites impact voltage and VAR flows. There is a need for in-depth analyses to be completed as these sites develop.

A map that shows the fire threat areas is shown in Figure 24. The colored shaded areas show the amount of BDT. The transmission hot spot areas were then plotted on the map to show the relationship of BDT to transmission hot spots. If generation could be located near transmission hot spots that could also burn forest fuels, then there could be public benefits from combining generation and fire threat reduction. As can be seen from the figure, there are vast areas in California that are susceptible to fire threats. The map also shows areas where forest fuel-fired biomass plants could provide transmission relief.

Given that the objective was to demonstrate a methodology for evaluating forest fueled-biomass plants to reduce transmission hot spots, the analysis was limited to the highest fire threat areas. A minimum of 120,000 BDT/yr as the cutoff point was selected. Figure 25 shows the areas selected for analysis. Most of the selected areas are not located near transmission hot spots but some are located near subtransmisson lines. If these areas could still demonstrate a transmission benefit by locating generation near existing substations and within high fire threat areas, then these could potentially be economical areas to develop.

In this analysis, the only criterion used was locating power plants within the highest fire threat zones. No other overlays were considered in the analysis such as high population density within a fire threat area.

The amount of generation that could be installed within each county was calculated as shown in Table 18. There are sixteen counties that lie within this highest fire threat area. Assuming a power plant could be installed in each county, as shown in Table 18; there will be up to 336 MW of biomass power plant that could be installed.

Table 18. Potential Biomass Generation by County[80]

NAME	2007 For/Chap MWe	2010 For/Chap MWe	2017 For/Chap MWe
BUTTE	13.07	14.11	15.68
CALAVERAS	9.66	10.43	11.59
EL DORADO	18.08	19.52	21.69
HUMBOLDT	43.31	46.77	51.97
LAKE	12.50	13.50	15.00
MENDOCINO	37.66	40.67	45.19
NEVADA	11.15	12.04	13.38
PLACER	7.36	7.95	8.83
PLUMAS	16.28	17.58	19.54
SHASTA	42.11	45.47	50.53
SISKIYOU	22.56	24.37	27.08
SONOMA	15.88	17.15	19.06
TEHAMA	15.38	16.61	18.46
TRINITY	29.76	32.14	35.71
TUOLUMNE	9.47	10.23	11.36
YUBA	6.75	7.29	8.09
Total	311	336	373

However, this average power generation can not be directly used in the analysis. By contemplating Figure 25, there are variations in the shading of the forest fire threat areas. The location of power plant would not necessarily be consistent across all the areas.

Wood waste must be transported by truck from the source to the power plants. Since there is an economic limitation to how far the wood waste can be transported, the transportation is limited to a 25 mile radius from a power plant location. Since there could be many transmission and distribution substations within a given region, there is a need to develop a methodology for locating biomass power plant.

For each bus in the region to be studied, a BDT and average megawatt of generation was calculated. DPC developed a process to select the location of a biomass generator recognizing that each bus selected will have a 25 mile radius from which wood waste would be transported to the generator site. There was no scientific approach that would automatically or mathematically determine which bus to select. Instead, DPC used the spreadsheet data, the maps, a compass and trial and error to select the buses to locate generation.

DPC assumed that any new biomass generator would be located near an existing substation. DPC then observed the distribution of the biomass region on the maps and attempted to locate the generator within the fire threat area. On the maps, DPC shows the bus location selected and the 25 mile radius from which wood waste would be transported. There are some locations that will have some overlap and there will be some areas that will not be within any 25 mile radius.

Table 19 shows the substations that DPC selected for the biomass study. The generator size to burn Forest and Shrub for each substation is shown in the last column marked Total. The total amount of generation is 235 MW as compared to Table 6 which showed that the total generation if all of the biomass material could be collected as 336 MW. DPC were able to only capture about 70 percent of the potential generation over the counties.

Table 19: Substations Selected as Biomass Generator Locations[81]

Buss Information			Annual MWe per Bus		
			25 mile Radius		
WECC	Name	County	FTTA Forest	FTTA Shrub	Total
31091	RDGE CBN	HUMBOLDT	27.04	0.04	27.08
31118	KEKAWAKA	TRINITY	24.25	0.13	24.38
31227	HGHLNDJ2	LAKE	12.36	4.08	16.45
31306	WILLITS	MENDOCINO	22.53	0.84	23.37
31360	MIRABEL	SONOMA	14.81	0.81	15.61
31452	TRINITY	TRINITY	16.32	0.40	16.72
31590	CEDR CRK	SHASTA	23.38	1.45	24.83
31610	TYLER	TEHAMA	9.87	0.08	9.94
31674	BIG MDWS	PLUMAS	13.24	0.18	13.42
32364	GRSS VLY	NEVADA	24.04	0.61	24.65
33926	CH.STNJT	TUOLUMNE	12.90	2.80	15.70
37110	JONESFRK	EL DORADO	9.38	0.57	9.95
38290	PARADISE	BUTTE	12.80	0.30	13.10
Total			222.91	12.29	235.20

While DPC was not able to collect 100 percent, the goal was to find high fire threat areas and determine if we could provide any transmission congestion relieve while reducing fire threats. DPC did not investigate whether the roads are adequate in the selected bus areas for transporting wood waste or the environmental impacts of building in the selected areas. As more research and site investigation is undertaken, locations can be changed and new power flows could be completed.

There were 12 other counties in California that are in the fire threat area but the BDT was under the 120,000 BDT minimum limits. That is not to say that these areas are not important but that for this study DPC needed to define study parameters. As mentioned earlier, if additional overlays were developed onto the maps for population, housing, employment and other public benefits, these other counties may have a higher priority for development. These other counties include:

Amador	San Benito
Madera	San Diego
Mariposa	San Luis Obispo
Lassen	Santa Cruz
Monterey	Sierra
Napa	Sonoma

If forest slash will be added in addition to forest fire threat materials, then there will be another 159 MW of generation from these areas. Table 20 shows the forest slash potential.

Table 20. Potential Generation from Forest, Shrub and Slash[82]

Buss Information			Annual MW per Bus 25mile Radius			
WECC	Name	County	FTTA Forest	FTTA Shrub	Harvest Slash	FTTA and Harvest Total
31091	RDGE CBN	HUMBOLDT	27.04	0.04	32.14	59.22
31118	KEKAWAKA	TRINITY	24.25	0.13	19.06	43.44
31227	HGHLNDJ2	LAKE	12.36	4.08	1.09	17.53
31306	WILLITS	MENDOCINO	22.53	0.84	12.13	35.50
31360	MIRABEL	SONOMA	14.81	0.81	2.20	17.82
31452	TRINITY	TRINITY	16.32	0.40	8.93	25.66
31590	CEDR CRK	SHASTA	23.38	1.45	14.38	39.20
31610	TYLER	TEHAMA	9.87	0.08	1.05	10.99
31674	BIG MDWS	PLUMAS	13.24	0.18	19.04	32.46
32364	GRSS VLY	NEVADA	24.04	0.61	15.47	40.11
33926	CH.STNJT	TUOLUMNE	12.90	2.80	5.70	21.40
37110	JONESFRK	EL DORADO	9.38	0.57	15.01	24.97
38290	PARADISE	BUTTE	12.80	0.30	12.82	25.92
Total			222.91	12.29	159.02	394.22

The first simulation study modeled the generation of the FTTA Forest and Shrub totaling 235 MW. Table 21 lists the Bus information and MW associated with them for each of the simulations.

Table 21. Summary of Potential Biomass Gen. from FTTA Forest, Shrub and Slash[83]

Buss Information			Annual MWs per Bus 25 mile Radius	
WECC	Name	County	FTTA Forest and Shrub	FTTA and Harvest Total
31091	RDGE CBN	HUMBOLDT	27.08	59.22
31118	KEKAWAKA	TRINITY	24.38	43.44
31227	HGHLNDJ2	LAKE	16.45	17.53
31306	WILLITS	MENDOCINO	23.37	35.50
31360	MIRABEL	SONOMA	15.61	17.82
31452	TRINITY	TRINITY	16.72	25.66
31590	CEDR CRK	SHASTA	24.83	39.20
31610	TYLER	TEHAMA	9.94	10.99
31674	BIG MDWS	PLUMAS	13.42	32.46
32364	GRSS VLY	NEVADA	24.65	40.11
33926	CH.STNJT	TUOLUMNE	15.70	21.40
37110	JONESFRK	EL DORADO	9.95	24.97
38290	PARADISE	BUTTE	13.10	25.92
		Total	235.20	394.22

Starting from the base case, the 235 MW of potential biomass generation was installed. A single power flow simulation revealed that there were 3 new critically overloaded 60 kV lines. Table 22 displays the 3 lines that were overloaded. These lines had to be reconductored prior to running any contingency analysis. The answer was to double the line rating. This solved the problem and the rest of the analysis continued.

Table 22. Overloaded 60 kV Lines[84]

From #	From Name	To #	To Name	Nom. kV	Old Line Rating	New Line Rating
31590	CEDR CRK	31598	KILARC	60	18 MVA	36 MVA
31588	WHITMORE	31598	KILARC	60	18 MVA	36 MVA
31588	WHITMORE	31592	DESCHUTS	60	18 MVA	36 MVA

While setting up the contingency analysis, DPC limited the contingency analysis to contain only the PG&E area which consisted of roughly 3300 contingencies, as opposed to the entire California area (IID, SDGE, LADWP, PGE, & SCE). Post contingency analysis results proved very beneficial. The resultant AMWCO value was 10,077 MW. This was an impact of 1,270 MW which resulted in a benefit ratio of -5.38 MW to 1 MW. This meant that for every 1 MW of biomass generation installed, it would reduce the overall system overload by over 5 MW. Table 23 shows how the benefit ratio is calculated:

Table 23. Benefit Ratio Calculation[85]

$$10{,}077 \text{ MW} - 11{,}347 \text{ MW} = -1{,}270 \text{ MW}$$

Exp. AMWCO   Base AMWCO   Impact Value

$$-1{,}270 \text{ MW} \div 236 \text{ MW} = -5.38 \text{ MW}$$

Impact Value   Installed MW   Benefit Ratio

The next biomass simulation was modeled with 393 MW of biomass potential that is composed of FTTA Forest, FTTA Shrub, and Slash. Table 19 above lists the MW value at each bus for the last biomass analysis. The MW values from the previous biomass analysis were edited to include the slash. The addition 157 MW of slash to the existing 235 MW of FTTA forest and shrub caused no additional overloads. The contingency analysis again was limited to only include the buses and lines in the PG&E area.

This contingency analysis with 393 MW of biomass potential generation resulted in an AMWCO value of 10,138 MW. The impact value is -1,209 MW which is comparable to the 235 MW biomass case of -1,270 MW. However, due to the additional MW, dividing the impact value by a larger installed MW value, you will naturally get a smaller benefit ratio. This 393 MW biomass case had a -3.07 MW to 1 MW benefit ratio. Table 24 is a summary of the power flow analysis.

Table 24. Summary of Biomass Potential Results[86]

	2010 Base Case	2010 Case w/ 235 MW of Biomass	2010 Case w/ 393 MW of Biomass
Contingencies:	251	244	241
AMWCO:	11,347 MW	10,077 MW	10,138 MW
Impact Value:	--	-1,270 MW	-1,209 MW
Benefit Ratio:	--	-5.38	-3.07

Figures 26 through 33 are maps of each county with biomass potential. The buses were selected close to the center of the county to ensure that a majority of the county is with in the 25 mile radius circle. The first of the two MW values are FTTA Forest and Shrub, the second MW value is the FTTA Forest, Shrub, and Slash.

Figure 24. Neighborhood Biomass Potential from Fire Threat Reduction Areas

Neighborhood Biomass Potential from Fire Threat Reduction Areas
(Annual)

Neighborhood Biomass Potential *
BDT per Year

- 1 - 20,000
- 20,000 - 40,000
- 40,000 - 60,000
- 60,000 - 80,000
- 80,000 - 100,000
- 100,000 - 120,000
- 120,000 - 140,000
- 140,000 - 160,000
- 160,000 - 180,000

* In order to assess potential site locations for biomass generation facilities, all in situ biomass values within a 25 mile radius of each 100 by 100 meter site are summed

WTLR and MW Injection
MW Needed 2005

- 2.51 - 4.00
- 4.01 - 5.00
- 5.01 - 6.00
- 6.01 - 8.00
- 8.01 - 19.43

February 9, 2005
CDF - FRAP

79

Figure 25. Neighborhood Biomass from Fire Threat Reduction Areas

Neighborhood Biomass Potential from Fire Threat Reduction Areas
(Annual)

Buss inside buffer
MW Needed 2005
- ▲ 2.6 - 4.0
- ▲ 4.1 - 5.0
- ▲ 5.1 - 6.0
- ▲ 6.1 - 7.0
- ▲ 7.1 - 12.7

Transmission Lines
— 12.0 - 69.9 KV
— 70.0 - 500.0 KV
☐ 25 Mile Buffer Area *

Neighborhood Biomass Potential **
BDT per Year
- 120,000 - 140,000
- 140,000 - 160,000
- 160,000 - 180,000

* Areas within 25 miles of high neighborhood biomass potential

** In order to assess potential site locations for biomass generation facilities, all in situ biomass values within a 25 mile radius of each 100 by 100 meter site are summed

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Figure 26. Humboldt and Trinity Fire Threatened Areas
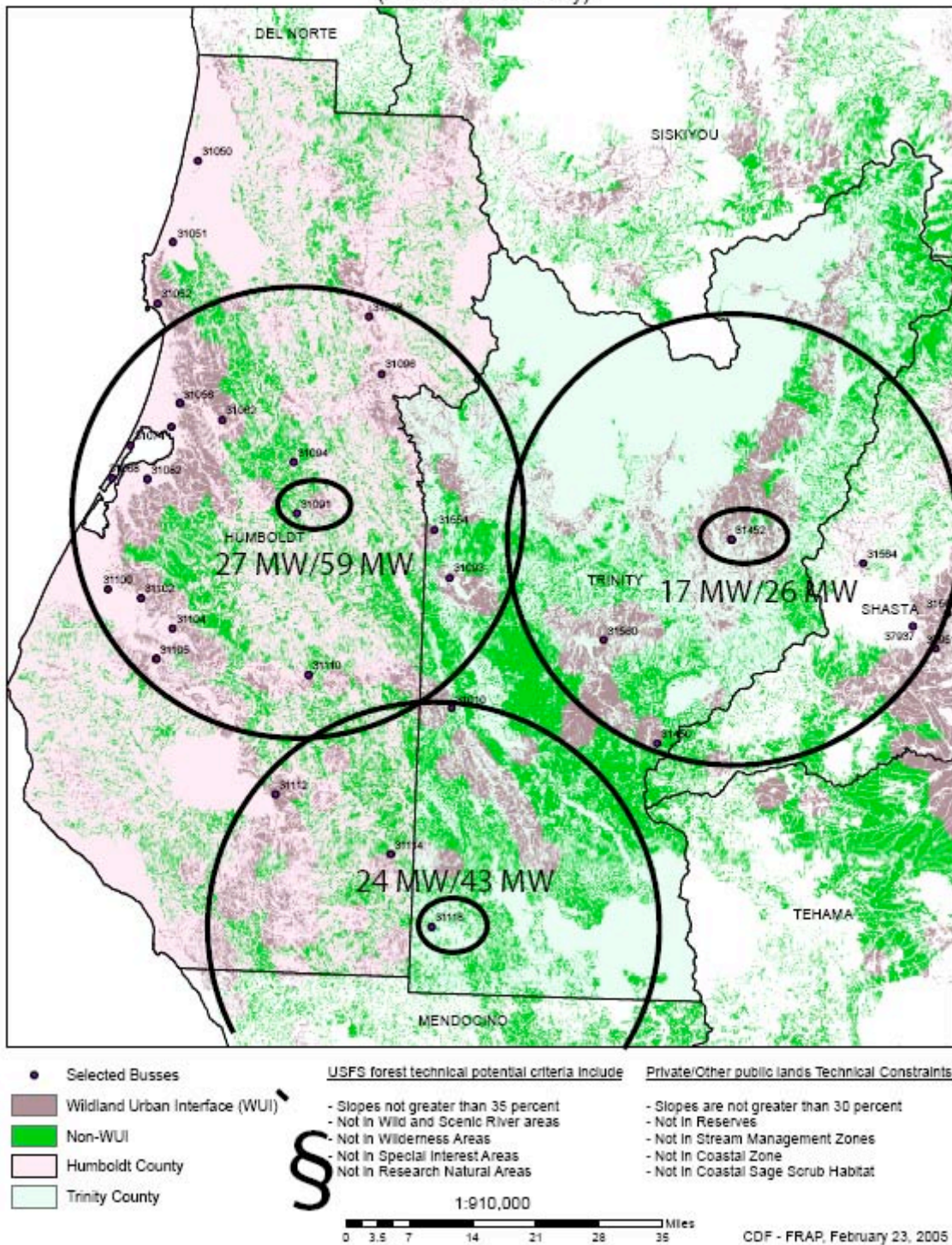
Figure 27. Mendocino and Lake Fire Threatened Areas

Forest and Chaparral Biomass inside Fire Threatened Areas
(Mendocino and Lake)

24 MW/35 MW

16 MW/18 MW

- HUMBOLDT
- TRINITY
- TEHAMA
- GLENN
- COLUSA
- MENDOCINO
- LAKE
- YOLO
- SONOMA
- NAPA

Legend:
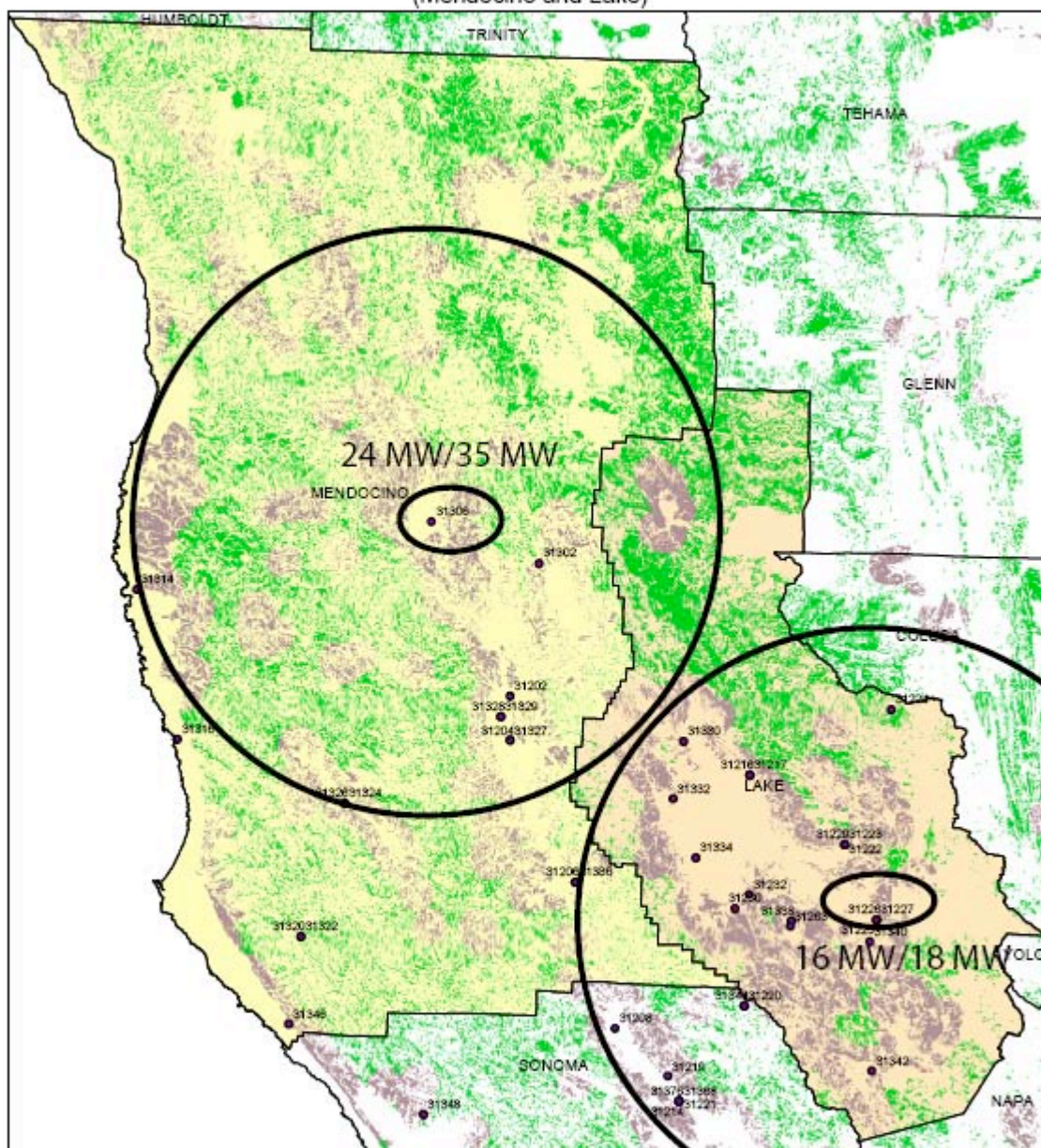
- • Selected Busses
- Wildland Urban Interface (WUI)
- Non-WUI
- Mendocino County
- Lake County

§

USFS forest technical potential criteria include

- Slopes not greater than 35 percent
- Not in Wild and Scenic River areas
- Not in Wilderness Areas
- Not in Special Interest Areas
- Not in Research Natural Areas

Private/Other public lands Technical Constraints

- Slopes are not greater than 30 percent
- Not in Reserves
- Not in Stream Management Zones
- Not in Coastal Zone
- Not in Coastal Sage Scrub Habitat

1:760,000

Miles
0 3 6 12 18 24 30

CDF - FRAP, February 23, 2005

Figure 28. El Dorado, Nevada, and Placer Fire Threatened Areas

Forest and Chaparral Biomass inside Fire Threatened Areas
(El Dorado, Nevada, and Placer)
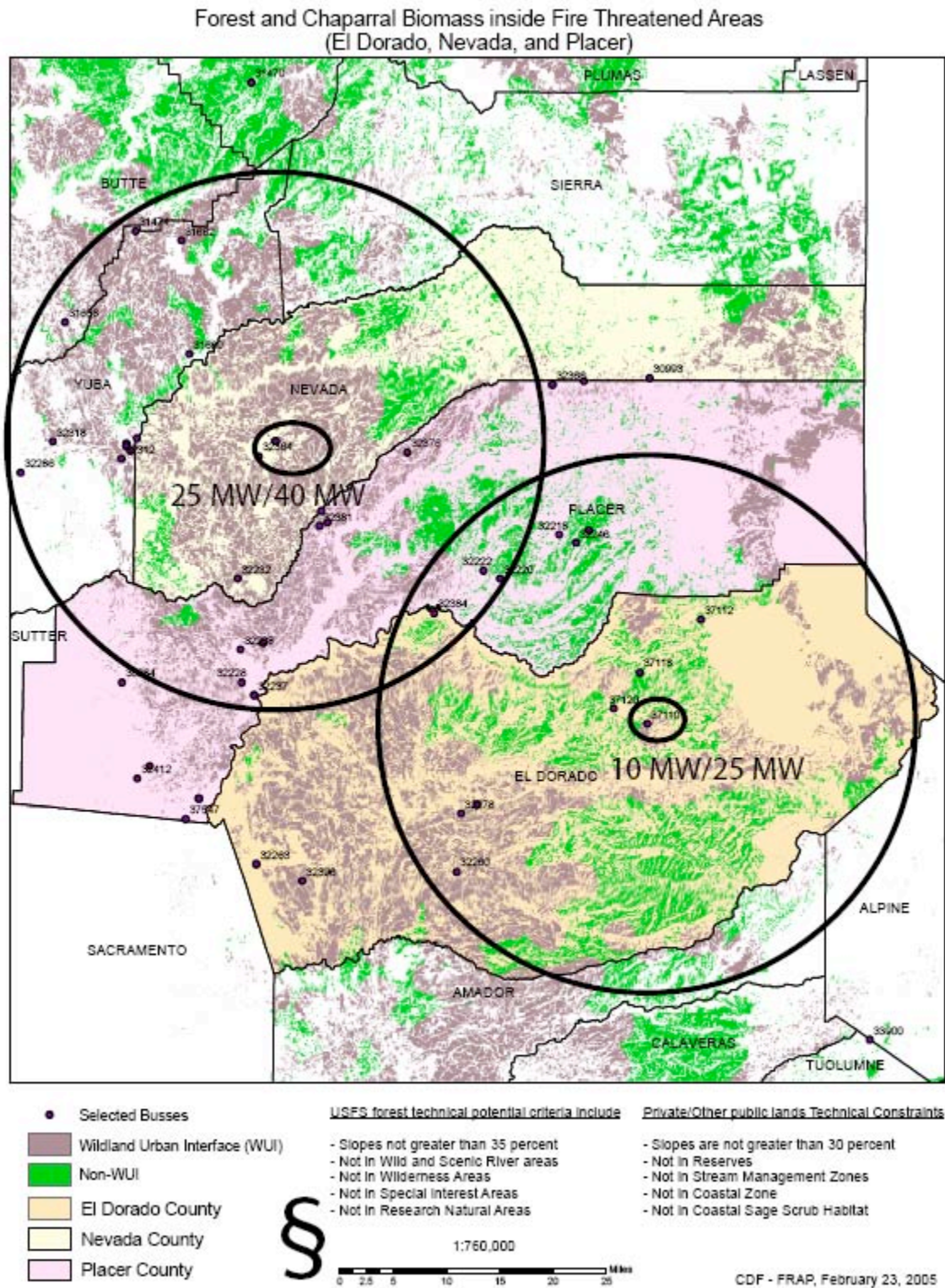
Figure 29. Plumas Fire Threatened Areas

Forest and Chaparral Biomass inside Fire Threatened Areas
(Plumas)

13 MW/32 MW

Legend:
- Selected Busses
- Wildland Urban Interface (WUI)
- Non-WUI
- PLUMAS

USFS forest technical potential criteria include
- Slopes not greater than 35 percent
- Not in Wild and Scenic River areas
- Not in Wilderness Areas
- Not in Special Interest Areas
- Not in Research Natural Areas

Private/Other public lands Technical Constraints
- Slopes are not greater than 30 percent
- Not in Reserves
- Not in Stream Management Zones
- Not in Coastal Zone
- Not in Coastal Sage Scrub Habitat

1:650,000

Miles
0 2.5 5 10 15 20 25

CDF - FRAP, February 23, 2005

Figure 30. Shasta and Tehama Fire Threatened Areas

Forest and Chaparral Biomass inside Fire Threatened Areas
(Shasta and Tehama)
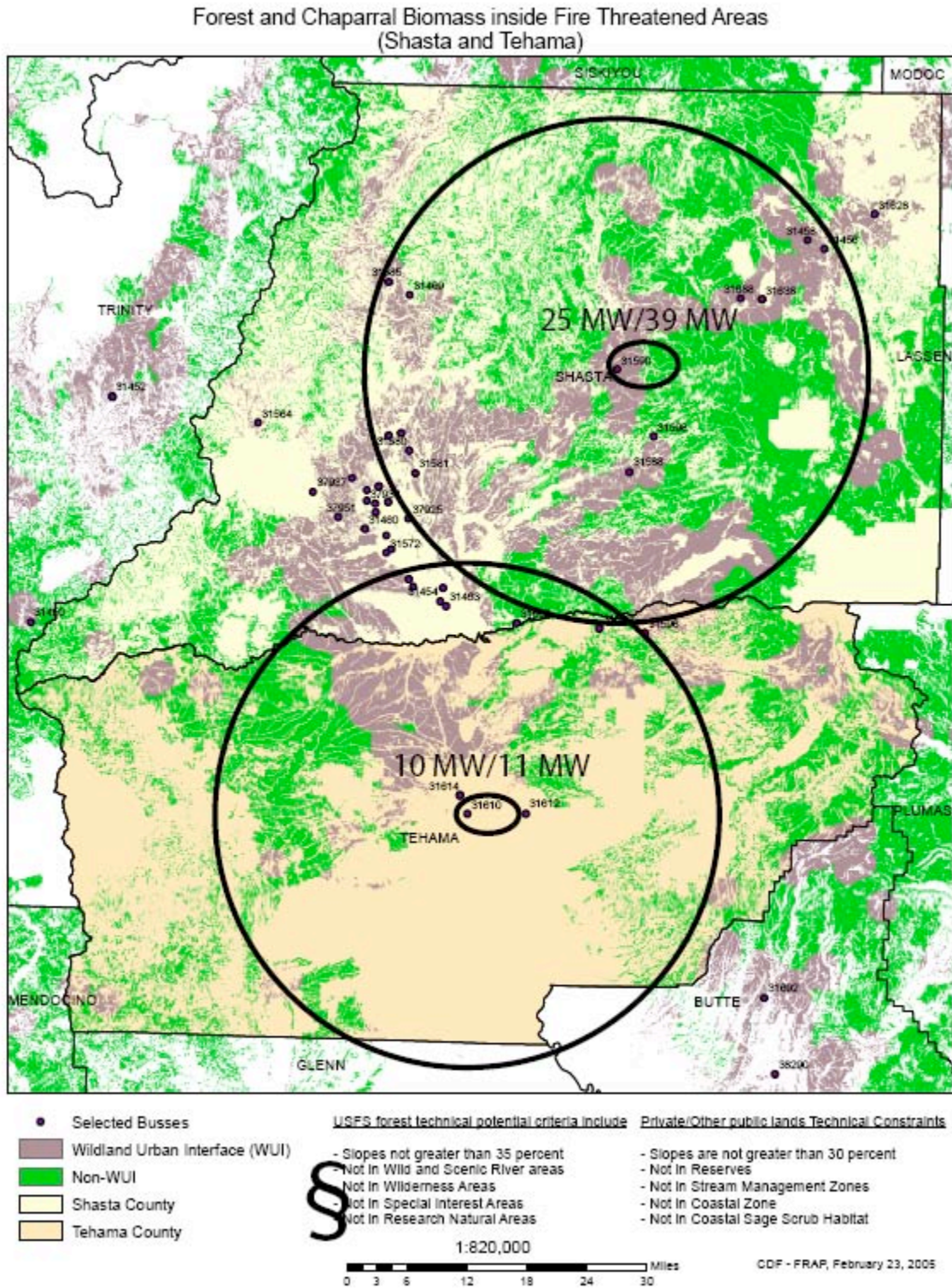
Figure 31. Sonoma Fire Threatened Areas

Forest and Chaparral Biomass inside Fire Threatened Areas
(Sonoma)

16 MW/18 MW

Selected Busses

Wildland Urban Interface (WUI)

Non-WUI

Sonoma County

USFS forest technical potential criteria include

- Slopes not greater than 35 percent
- Not in Wild and Scenic River areas
- Not in Wilderness Areas
- Not in Special Interest Areas
- Not in Research Natural Areas

Private/Other public lands Technical Constraints

- Slopes are not greater than 30 percent
- Not in Reserves
- Not in Stream Management Zones
- Not in Coastal Zone
- Not in Coastal Sage Scrub Habitat

1:550,000

Miles
0   2   4   8   12   16   20

CDF - FRAP, February 23, 2005

Figure 32. Butte and Yuba Fire Threatened Areas

Forest and Chaparral Biomass inside Fire Threatened Areas
(Butte and Yuba)
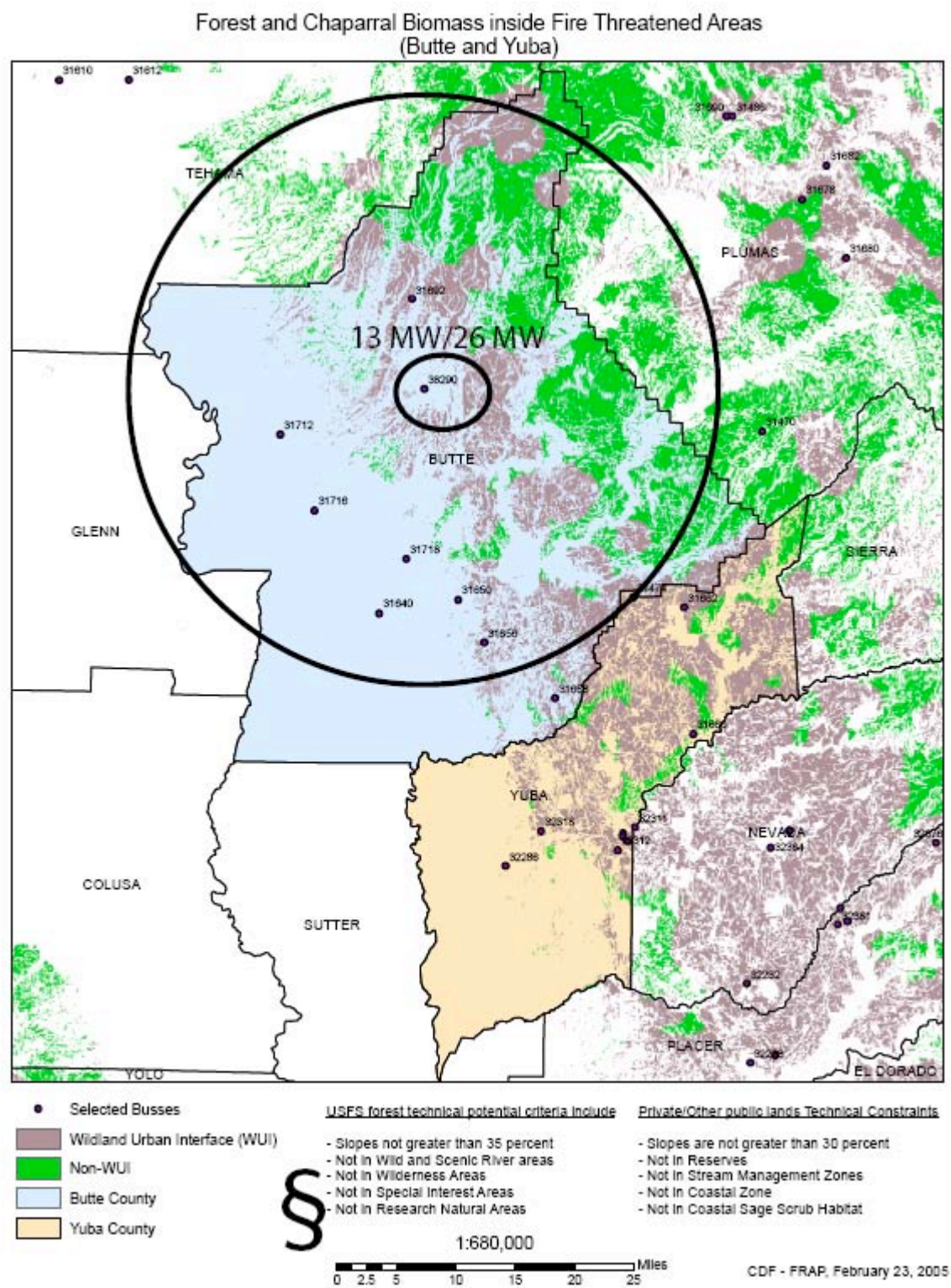
Figure 33. Calaveras and Tuolumne Fire Threatened

Forest and Chaparral Biomass inside Fire Threatened Areas
(Calaveras and Tuolumne)
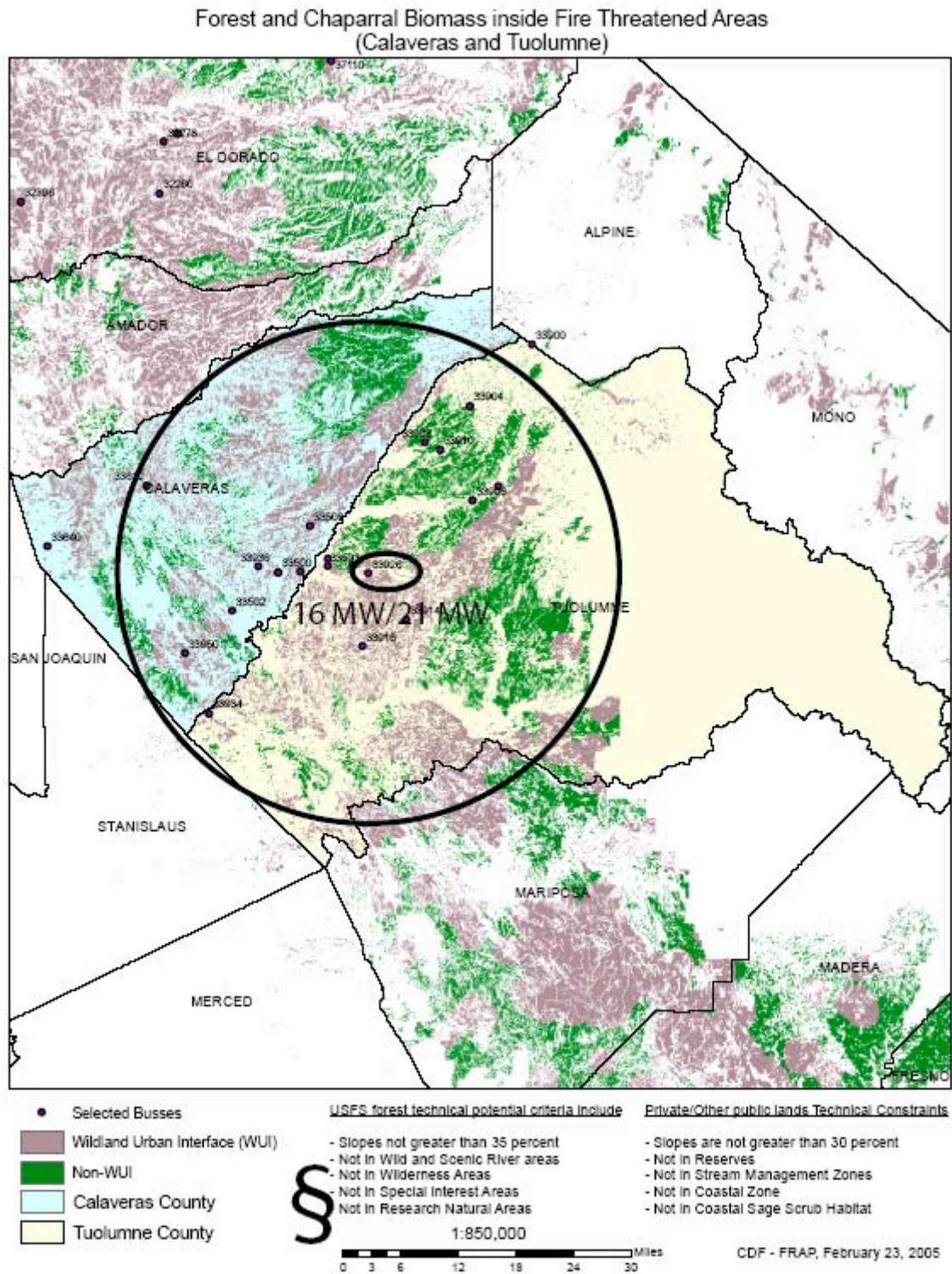
Areas

Economic Analysis Of Fire Threat Forest Fuels

2010 Results

The economics for the installation of biomass power plants using fire threat forest fuels was estimated by using the levelized cost model for fluidized bed combustion. For 2010, for all the sites, the LCOE's lies in the range of $.0649/kWh to $0.1321/kWh with PTC (in current dollar) for an installed capital cost of $2400/kW.[87] This estimate also assumes 25% net efficiency, 8.4% interest on debt, 16% return on equity, 67% debt ratio, 85% capacity factor, 20 year economic life, and MACRS depreciation (5-year property). For fire threat forest fuels, $40/BDT fuel cost was assumed. Based on the power flow analysis there is no transmission costs for the installation of biomass plants in the sites investigated. The benefit ratio was -3.07 MW. Signifying that for every 1 MW of biomass power plant installed there is a reduction in total overloads by 3.07 MW.

To evaluate the cost competitiveness of the installation of biomass power plant using forest fuels, the biomass LCOE's (with PTC) were compared to LCOE's of combined cycle, wholesale prices of electricity (2003 CEC forecast and E3 CPUC forecast), and CPUC's market price referents (MPR).

Based on Table 25, the economic potential by 2010 using current dollar analysis are:

> Zero megawatt using CEC 2003 wholesale price forecast comparison.
>
> 59 MW in Humbolt County using E3 CPUC wholesale price forecast comparison.
>
> 181 MW (59 MW in Humboldt County+ 43 MW in Trinity County + 39 MW in Shasta County + 40 MW in Nevada County) using LCOE of combined cycle comparison
>
> Zero megawatt using MPR comparison.

Thus, using the strategic value analysis methodology it maybe economically viable to develop up to 181 MW of biomass power plant by year 2010 using fire threat forest biomass depending on the criteria of comparison (in current dollar).

Table 25. 2010 LCOE using fluidized bed with and without PTC, wholesale prices of electricity and LCOE of combined cycle (current dollar). Zero transmission costs[88]

Name	County	Capacity (MW)	Transmission Impact ratio	2010 No PTC	2010 with PTC	Wholesale Price CEC 2003 forecast for 2010	Wholesale Price E3 - CPUC Forecast for 2010*	Market Price Referents	LCOE Combined cycle for 2010*
RDGE CBN	Humboldt	59	-3.07	0.0693	0.0649	0.0426	0.06304	0.0605	0.07419
KEKAWAKA	Trinity	43	-3.07	0.0750	0.0707	0.0426	0.06304	0.0605	0.07419
HGHLNDJ2	Lake	18	-3.07	0.1044	0.1000	0.0426	0.06304	0.0605	0.07419
WILLITS	Mendocino	35	-3.07	0.0799	0.0755	0.0426	0.06304	0.0605	0.07419
MIRABEL	Sonoma	18	-3.07	0.1044	0.1000	0.0426	0.06304	0.0605	0.07419
TRINITY	Trinity	26	-3.07	0.0889	0.0845	0.0426	0.06304	0.0605	0.07419
CEDR CRK	Shasta	39	-3.07	0.0772	0.0728	0.0426	0.06304	0.0605	0.07419
TYLER	Tehama	11	-3.07	0.1365	0.1321	0.0426	0.06304	0.0605	0.07419
BIG MDWS	Plumas	32	-3.07	0.0823	0.0779	0.0426	0.06304	0.0605	0.07419
GRSS VLY	Nevada	40	-3.07	0.0766	0.0722	0.0426	0.06304	0.0605	0.07419
CH.STNJT	Tuolumne	21	-3.07	0.0972	0.0928	0.0426	0.06304	0.0605	0.07419
JONESFRK	El Dorado	25	-3.07	0.0903	0.0859	0.0426	0.06304	0.0605	0.07419
PARADISE	Butte	26	-3.07	0.0889	0.0845	0.0426	0.06304	0.0605	0.07419
		393							

2017 Results

For 2017, for all the sites, the LCOE's lies in the range of $.0552/kWh to $0.1210/kWh with PTC (in current dollar) for an installed capital cost of $2200/kW. By 2017, we assumed a dramatic improvement in net efficiency of 30%. This estimate also assumed 8.4% interest on debt, 16% return on equity, 67% debt ratio, 85% capacity factor, 20 year economic life, and MACRS depreciation (5-year property). Fuel cost is also assumed at $40/BDT for this forest fuels. Again, based on the power flow analysis there is no transmission costs for the installation of biomass plants in the sites investigated. The benefit ratio was -3.0 MW. Signifying that for every 1 MW of biomass power plant installed there is a reduction in total overloads by 3.0 MW.

Based on Table 27, the economic potential by 2017 using current dollar analysis are:

> 59 MW in Humboldt County using CEC 2003 wholesale price forecast comparison.

> 248 MW (59 MW in Humboldt County + 43 MW in Trinity County + 35 MW in Mendocino County + 39 MW in Shasta County + 32 MW in Plumas County + 40 MW in Nevada) using E3 CPUC wholesale price forecast comparison.

> 382 MW (all identified sites except 11 MW in Tehama County) using LCOE of combined cycle comparison

> 59 MW in Humboldt County using MPR comparison.

Thus, using the strategic value analysis methodology it maybe economically viable to develop 59 MW to 382 MW of biomass power plant by year 2017 using fire threat forest biomass depending on what price forecast and LCOEs of combined cycle to compare with.

Table 26.2017 LCOE's of fluidized bed with and without PTC, wholesale prices of electricity and LCOE of combined cycle (current dollar). Zero transmission costs[89]

Name	County	Capacity (MW)	Transmission Impact ratio	2017 No PTC	2017 with PTC	Wholesale Price CEC 2003 forecast for 2017	Wholesale Price E3 - CPUC Forecast for 2017*	Market Price Referents	LCOE Combined cycle for 2017*
RDGE CBN	Humboldt	59	-3.0	0.0595	0.0552	0.0587	0.07164	0.0605	0.09152
KEKAWAKA	Trinity	43	-3.0	0.0652	0.0608	0.0587	0.07164	0.0605	0.09152
HGHLNDJ2	Lake	18	-3.0	0.0939	0.0895	0.0587	0.07164	0.0605	0.09152
WILLITS	Mendocino	35	-3.0	0.0699	0.0655	0.0587	0.07164	0.0605	0.09152
MIRABEL	Sonoma	18	-3.0	0.0939	0.0895	0.0587	0.07164	0.0605	0.09152
TRINITY	Trinity	26	-3.0	0.0787	0.0743	0.0587	0.07164	0.0605	0.09152
CEDR CRK	Shasta	39	-3.0	0.0673	0.0629	0.0587	0.07164	0.0605	0.09152
TYLER	Tehama	11	-3.0	0.1253	0.1210	0.0587	0.07164	0.0605	0.09152
BIG MDWS	Plumas	32	-3.0	0.0723	0.0679	0.0587	0.07164	0.0605	0.09152
GRSS VLY	Nevada	40	-3.0	0.0667	0.0623	0.0587	0.07164	0.0605	0.09152
CH.STNJT	Tuolumne	21	-3.0	0.0868	0.0824	0.0587	0.07164	0.0605	0.09152
JONESFRK	El Dorado	25	-3.0	0.0800	0.0757	0.0587	0.07164	0.0605	0.09152
PARADISE	Butte	26	-3.0	0.0787	0.0743	0.0587	0.07164	0.0605	0.09152
		393							

LANDFILL GAS, DAIRY MANURE, WASTEWATER TREATMENT, AND URBAN FUELS

POWER FLOW RESULTS FOR LANDFILL GAS, DAIRY, WASTEWATER AND URBAN FUELS

2010 Results

Four specific biomass types were defined for 2010 power flow analysis, which are listed as follows:

> Landfill Gas (LFGTE)
> Dairy Manure (Dairy)
> Urban Fuels (Urban)
> Wastewater Treatment Plant (WWTP)

Urban fuels were not considered by 2010 in the power flow analysis. Table 27 shows the selected 27 counties with biomass economic potential for three biomass categories. The projected distribution of the biomass resources are 39 MW dairy manure, 86 MW wastewater treatment and 325 MW landfill gas for a total of 450 MW. Depending on the incremental size of the generators and how the biomass resources are aggregated, many of the biomass resources would be eliminated. For example, if the minimum size of a dairy manure facility was 5 MW, then only Riverside, San Bernardino and Tulare counties would have any dairy generation. If the minimum size of a landfill gas was 25 MW, then only Alameda, Los Angeles, Orange and San Diego counties would have generators. For this analysis, we will be aggregating the biomass resources and considering these as one biomass resource.

Table 27. Potential Biomass Generation by County[90]

NAME	Dairy MWe	WWTP MWe	LFGTE NET MWe	Gross MWe	Existing MW	Economical Potential
ALAMEDA	0.05	5.32	29.89	35.26	8.22	27.04
BUTTE	0.06	0.40	1.12	1.59	0.00	1.59
CONTRA COSTA	0.15	2.59	10.88	13.62	3.00	10.62
EL DORADO	0.00	0.22	-0.15	0.07	0.00	0.07
GLENN	0.11	0.00	0.00	0.11	0.00	0.11
IMPERIAL	0.00	0.36	1.35	1.72	0.00	1.72

KERN	3.45	1.69	9.70	14.84	0.28	14.56
LOS ANGELES	0.00	29.48	116.08	145.56	121.10	24.46
MARIN	0.81	0.70	3.11	4.62	0.00	4.62
NEVADA	0.00	0.13	0.47	0.61	0.00	0.61
ORANGE	0.00	9.92	58.37	68.29	34.98	33.31
PLACER	0.08	0.45	3.03	3.56	1.00	2.56
RIVERSIDE	8.81	4.34	16.83	29.98	1.67	28.31
SAN BENITO	0.08	0.07	0.69	0.84	0.00	0.84
SAN BERNARDINO	16.15	3.90	10.96	31.01	0.00	31.01
SAN DIEGO	0.61	8.11	28.24	36.96	16.10	20.86
SAN FRANCISCO	0.00	2.98	0.00	2.98	0.51	2.47
SAN JOAQUIN	2.05	1.51	7.36	10.91	0.80	10.11
SAN LUIS OBISPO	0.00	0.45	4.45	4.90	0.00	4.90
SAN MATEO	0.00	2.02	4.96	6.98	1.90	5.08
SANTA BARBARA	0.03	0.52	1.63	2.18	0.00	2.18
SANTA CLARA	0.00	7.68	6.24	13.92	9.23	4.69
SOLANO	0.00	0.56	0.00	0.56	0.00	0.56
STANISLAUS	0.73	0.00	0.00	0.73	0.00	0.73
TULARE	5.65	0.00	0.79	6.44	0.00	6.44
VENTURA	0.00	2.03	7.72	9.75	3.30	6.45
YUBA	0.16	0.12	1.52	1.80	0.00	1.80
	38.98	85.56	325.25	449.79	202.09	247.71

Included in the gross potential is 202 MW of existing biomass generation. The problem is that we do not know the distribution of the existing resources for dairy, wastewater treatment and landfill gas. A simple method was developed to distribute the existing resources as shown in Table 28. In Table 28, we list the total gross resource potential

by biomass type. We then calculate the percent mix of the gross potential. This percentage is used to distribute the existing resources across the biomass types. For example, dairy manure comprises 8.7 percent of the total gross potential so 8.7 percent of the existing generation will be allocated to dairy manure. The result is a net potential of new biomass resource by biomass type. We then adjusted the gross potential of each county's biomass resources by the results in Table 28.

Table 28. Distribution of Existing Biomass Generation[91]

2010	Total Gross	% Mix	Existing MW	Net Potential
Dairy	38.98	8.7%	17.51	21.47
WWTP	85.56	19.0%	38.44	47.12
LFGTE	325.25	72.3%	146.13	179.12
Urban	0	0.00%	0.00	0.00
Total	449.79	100%	202.09	247.71

Since the objective of the injection of distributed biomass resources was to located generation near transmission hot spots, CDF/FRAP developed a list of hot spot locations by county. DPC then eliminated those counties that did not have hot spots. This reduced the number of counties to 15. We then removed all of the high voltage buses since the objective was to have distributed generation. We then installed the aggregated MW net potential across arbitrary bus locations in equal quantities, as shown in Table 29.

Table 29. Bus Locations Selected for Study[92]

CNTYNAME	NAME	AREANAME	NOM_KV	WECC	2010 MW Injection
ALAMEDA	EDS GRNT	PG AND E	115	32812	3
ALAMEDA	GRANT	PG AND E	115	35104	3
ALAMEDA	EASTSHRE	PG AND E	115	35105	3
ALAMEDA	MT EDEN	PG AND E	115	35106	3
ALAMEDA	DUMBARTN	PG AND E	115	35107	3
ALAMEDA	FREMNT	PG AND E	115	35110	3
ALAMEDA	JARVIS	PG AND E	115	35111	3
ALAMEDA	JV BART	PG AND E	115	35115	3

ALAMEDA	CRYOGEN	PG AND E	115	35116	3
ALAMEDA	NORTHERN	PG AND E	115	36851	3
IMPERIAL	HIGHLINE	IMPERIAL	92	21039	2
KERN	LAKEVIEW	PG AND E	70	34872	5
KERN	WHEELER	PG AND E	70	34874	5
KERN	TEJON	PG AND E	70	34876	5
LOS ANGELES	LA FRESA	SOCALIF	66	24073	4
LOS ANGELES	WALNUT	SOCALIF	66	24157	4
LOS ANGELES	CENTER S	SOCALIF	66	24203	4
LOS ANGELES	OLINDA	SOCALIF	66	24211	4
MARIN	IGNACO A	PG AND E	60	32664	5
ORANGE	CAPSTRNO	SANDIEGO	138	22112	7
ORANGE	LAGNA NL	SANDIEGO	138	22396	7
ORANGE	MARGARTA	SANDIEGO	138	22432	7
ORANGE	PICO	SANDIEGO	138	22656	7
ORANGE	TRABUCO	SANDIEGO	138	22860	7
PLACER	PENRYN	PG AND E	60	32270	3
RIVERSIDE	VALLEYSC	SOCALIF	115	24160	7
RIVERSIDE	MIRAGE	SOCALIF	115	24807	7
RIVERSIDE	BANNING	SOCALIF	115	24814	7
RIVERSIDE	GARNET	SOCALIF	115	24815	7
RIVERSIDE	SANTA RO	SOCALIF	115	24816	7
RIVERSIDE	EISENHOW	SOCALIF	115	24817	7
RIVERSIDE	FARREL	SOCALIF	115	24818	7
SAN BERNARDINO	CHINO	SOCALIF	66	24024	5
SAN BERNARDINO	AMERON	SOCALIF	66	24032	5
SAN BERNARDINO	PADUA	SOCALIF	66	24111	5

SAN BERNARDINO	VSTA	SOCALIF	66	24902	5
SAN BERNARDINO	YUCCA	SOCALIF	115	24809	5
SAN BERNARDINO	HI DESER	SOCALIF	115	24810	5
SAN DIEGO	DIVISION	SANDIEGO	69	22172	3
SAN DIEGO	MAIN ST	SANDIEGO	69	22420	3
SAN DIEGO	MELROSE	SANDIEGO	69	22440	3
SAN DIEGO	NATNLCTY	SANDIEGO	69	22548	3
SAN DIEGO	SAMPSON	SANDIEGO	69	22700	3
SAN DIEGO	TALEGA	SANDIEGO	69	22836	3
SAN DIEGO	URBAN	SANDIEGO	69	22868	3
SAN FRANCISCO	MISSON	PG AND E	115	33203	3
SAN LUIS OBISPO	TEMPLETN	PG AND E	230	30905	5
SAN MATEO	BURLNGME	PG AND E	60	33356	5
SANTA CLARA	PLO ALTO	PG AND E	115	38028	5
VENTURA	MANDALAY	SOCALIF	66	24223	7
					228

The ending result is that out of the 248 MW net potential only 228 MW may be installed. The reasons for a lower quantity are that the megawatts increments were in whole numbers and some of the counties did not have transmission hot spots and were eliminated.

Since we could exactly match the biomass distribution that was calculated in Table 28, we revised the distribution of the biomass types to match the 228 MW that was installed and modeled. Table 30 shows the revised distribution of biomass resources.

Table 30. Final 2010 Biomass Distribution by Type[93]

Biomass	MW
Dairy Manure	21
WWTP	45
LFGTE	162
Total	228

Several power flow simulations were completed. A power flow of the 2010 summer peak base case was completed as a benchmark of the current status of the California transmission system. This base case simulation produces a base AMWCO value which would be used to compare to the biomass alternatives. Table 31 shows the results of the 2010 summer base case.

Table 31. 2010 Summer Base Case Results[94]

2010 Summer Base Case	
Contingencies:	343
Violations:	554
AMWCO:	15,753 MW

Table 32 shows the results of having 228 MW of biomass installed in 15 counties.

Table 32. 2010 Summer Biomass Case Results for 228 MW[95]

2010 Summer Case /w 236 MW	
Contingencies:	327
Violations:	528
AMWCO:	14,717 MW
AMWCO Impact:	- 1,036 MW
Benefit Ratio:	- 4.54

The addition of 228 MW into the system at these locations proved to be very beneficial. The benefit ratio was -4.54 MW. Signifying that for every 1 MW of biomass installed reduced the total overloads by 4.54 MW.

2017 Results

The same procedures were followed for the 2017 analysis as in the 2010 case.

The major differences were:

    Urban fuel was added in 2017
    Additional calculations undertaken to account for the existing capacity since some of this existing capacity was included from 2010
    Projected 2010 biomass generation and associated bus locations were carried over into 2017
    Where needed, generation was increased at the 1010 bus locations to simulate continued biomass development

In 2017, 39 counties were selected that with biomass economic potential for the four biomass categories. These are shown in Table 33.

Table 33. 2017 Potential Biomass Generation by County[96]

NAME	URBAN MW	Dairy MW	WWTP MW	LFGTE MW	TOTAL MW	EXISTING CAP	ECONOMIC POTENTIAL
ALAMEDA	48.51	0.03	3.13	37.41	89.08	8.2	80.86
ALPINE	0.09	-	-	-	0.09	-	0.09
AMADOR	0.99	-	0.09	0.58	1.66	-	1.66
BUTTE	6.24	0.04	0.24	1.63	8.15	4.1	4.01
CALAVERAS	0.90	-	0.02	0.50	1.42	-	1.42
CONTRA COSTA	27.85	0.09	1.52	13.89	43.35	3.0	40.35
EL DORADO	6.28	-	0.23	(0.14)	6.37	-	6.37
FRESNO	23.69	1.56	1.45	10.79	37.50	6.6	30.91
GLENN	0.96	0.27	0.04	0.32	1.60	-	1.60
LOS ANGELES	288.46	-	17.35	182.58	488.38	156.8	331.5
MARIN	12.15	0.21	0.41	4.33	17.10	-	17.10
MARIPOSA	0.70	-	-	0.24	0.94	-	0.94
MERCED	4.68	6.81	0.27	3.50	15.27	-	15.27
MONTEREY	13.78	0.04	0.49	4.50	18.82	6.1	12.76
NAPA	5.27	-	0.12	0.64	6.03	1.4	4.63
NEVADA	3.70	-	0.15	0.48	4.33	-	4.33
ORANGE	93.98	-	5.84	74.16	173.97	35.0	138.9
PLACER	9.03	0.05	0.26	3.93	13.28	7.9	5.35
RIVERSIDE	30.84	5.18	1.99	19.95	57.95	6.6	51.39

SACRAMENTO	41.03	0.69	3.85	10.18	55.75	11.1	44.62
SAN BENITO	1.18	0.03	0.04	0.90	2.16	-	2.16
SAN BERNARDINO	43.46	9.61	2.30	13.02	68.39	-	68.39
SAN DIEGO	74.78	0.30	4.74	38.31	118.13	16.1	102.0
SAN FRANCISCO	12.71	-	1.76	-	14.47	0.5	13.96
SAN JOAQUIN	13.47	3.84	1.01	16.51	34.83	6.1	28.74
SAN LUIS OBISPO	7.39	-	0.21	3.58	11.18	-	11.18
SAN MATEO	22.58	-	1.19	8.27	32.04	1.9	30.14
SANTA BARBARA	5.24	0.02	0.31	2.28	7.85	-	7.85
SANTA CLARA	96.61	-	4.52	10.88	112.00	9.2	102.7
SANTA CRUZ	9.86	0.01	0.61	1.54	12.02	3.9	8.10
SOLANO	9.26	0.06	0.82	6.08	16.21	1.0	15.21
SONOMA	15.36	1.10	0.49	4.72	21.67	6.6	15.08
STANISLAUS	12.87	6.81	0.94	2.62	23.24	15.8	7.49
SUTTER	2.43	-	0.12	-	2.55	-	2.55
TEHAMA	1.63	0.08	0.06	0.72	2.48	-	2.48
TRINITY	0.23	-	-	0.05	0.27	-	0.27
VENTURA	18.83	-	1.20	10.75	30.77	3.3	27.47
YOLO	5.60	0.03	0.57	2.41	8.60	7.4	1.20
YUBA	1.58	0.11	0.10	2.93	4.72	-	4.72
	974.2	37.0	58.4	495.0	1,564.6	318.6	1,246.

The distribution of the existing capacity in 2017 was a little different than 2010. Since we had already allocated the 2010 existing capacity across dairy, wastewater treatment and landfill gas, the 2017 existing capacity had to be allocated to urban fuel only. Otherwise we would be double counting existing capacity. The 2017 net incremental MW represents the maximum new biomass generation that could be added in 2017. For example, in 2017 the total dairy manure was projected to be 36.99 MW. But since we had already added 21.27 MW in 2010, the 2017 net new dairy manure capacity would be 15.52 MW. The 2010 and 2017 total biomass generation continues to add up to 1,246 MW after we adjust for total existing capacity.

Table 34 Distribution of 2017 Biomass Potential by Type[97]

	URBAN MW	Dairy MW	WWTP MW	LFGTE MW	Gross MW	EXISTING CAP	ECONOMIC POTENTIAL
2017 Projections	974.19	36.99	58.43	495.01	1,564.62	318.61	1,246.00
2010 Distribution	0	21.47	47.12	179.12	247.71	202	
Net	974.19	15.52	11.31	315.89	1,316.91	116.61	1,246.00
Existing 2017 MW	116.61	0	0	0			
2017 Net Incremental MW	857.57	15.52	11.31	315.89	1,316.91	116.61	1,246.00
2010 and 2017 Total	857.57	36.99	58.43	495.01	1,564.62	318.61	1,246.00

Table 35 lists the transmission buses selected for the study. The same process was followed for the selection and distribution of biomass generation as in 2010. We included the 2010 bus locations and increased generation at these buses to reflect continued expansion of the facilities as additional resources become available.

Since urban fuels were determined to be not substantially developed until after 2010, we elected to reduce its total net development by 2017. We decided to limit the total

biomass development for the transmission load flow analysis to 952 MW for 2017. We assumed full development of the dairy manure, wastewater treatment and landfill gas by 2017. The limited biomass resource was urban fuel. The net potential was limited to 361.57 MW, or 42 percent of the total net potential. The resulting biomass distribution was calculated and the results shown in Table 35. Remember that since we are not modeling individual biomass types but are aggregating the biomass resources, the distribution of biomass resources is strictly for example purposes.

Table 35. 2017 Final Biomass Distribution[98]

Biomass Type	MW
Dairy Manure	37
WWTP	58
LFGTE	499
Urban Fuel	361
Total	952

After we selected the aggregated potential by county, we then selected the transmission buses that had the lowest bus voltages to reflect as close as possible the concept of distribution generation. Table 36 below lists the bus locations and injection biomass generation.

Table 36. Counties Locations Selected for Study[99]

CNTYNAME	NAME	AREANAME	NOM_KV	NUMBER	2017 MW
ALAMEDA	EDS GRNT	PG AND E	115	32812	8
ALAMEDA	GRANT	PG AND E	115	35104	8
ALAMEDA	EASTSHRE	PG AND E	115	35105	8
ALAMEDA	MT EDEN	PG AND E	115	35106	8
ALAMEDA	DUMBARTN	PG AND E	115	35107	8
ALAMEDA	FREMNT	PG AND E	115	35110	8
ALAMEDA	JARVIS	PG AND E	115	35111	8
ALAMEDA	JV BART	PG AND E	115	35115	8
ALAMEDA	CRYOGEN	PG AND E	115	35116	8
ALAMEDA	NORTHERN	PG AND E	115	36851	8

AMADOR	PNE GRVE	PG AND E	60	33608	4
BUTTE	PEACHTON	PG AND E	60	31642	5
BUTTE	TRES VIS	PG AND E	60	31640	5
BUTTE	BIGGSJCT	PG AND E	60	31644	5
BUTTE	TBLE MTN	PG AND E	60	31718	5
BUTTE	ESQUON	PG AND E	60	31716	5
BUTTE	BUTTE	PG AND E	60	31712	5
BUTTE	CHICO A	PG AND E	60	31710	5
BUTTE	DE SABLA	PG AND E	60	31692	5
BUTTE	BANGOR	PG AND E	60	31658	5
BUTTE	PALERMO	PG AND E	60	31656	5
CONTRA COSTA	ROSEMORE	PG AND E	69	38256	8
CONTRA COSTA	RSMRE TP	PG AND E	69	38306	8
CONTRA COSTA	POSO J2	PG AND E	70	34236	8
FRESNO	AUBRYTP	PG AND E	70	34491	10
FRESNO	AUBERRY	PG AND E	70	34493	10
FRESNO	COPPRMNE	PG AND E	70	34464	10
FRESNO	RIVERROC	PG AND E	70	34454	10
IMPERIAL	HIGHLINE	IMPERIAL	92	21039	2
KERN	LAKEVIEW	PG AND E	70	34872	5
KERN	WHEELER	PG AND E	70	34874	5
KERN	TEJON	PG AND E	70	34876	5
LOS ANGELES	LA FRESA	SOCALIF	66	24073	15
LOS ANGELES	WALNUT	SOCALIF	66	24157	15
LOS ANGELES	CENTER S	SOCALIF	66	24203	15
LOS ANGELES	OLINDA	SOCALIF	66	24211	15
MADERA	BORDEN	PG AND E	70	34256	7
MADERA	TRIGO J	PG AND E	70	34255	7
MADERA	TRIGO	PG AND E	70	34254	7
MADERA	MADERA	PG AND E	70	34252	7
MADERA	BONITA	PG AND E	70	34238	7

MARIN	IGNACO A	PG AND E	60	32664	5
MERCED	MERCED	PG AND E	70	34202	5
MERCED	CANAL	PG AND E	70	34206	5
MERCED	LIVNGSTN	PG AND E	70	34204	5
MERCED	MERCED M	PG AND E	115	34146	5
MERCED	ATWATR J	PG AND E	115	34110	5
MERCED	MERCED	PG AND E	115	34144	5
MERCED	CRESSEY	PG AND E	115	34140	5
MERCED	EL CAPTN	PG AND E	115	34138	5
MONTEREY	FIRESTNE	PG AND E	60	36050	10
NAPA	NAPA	PG AND E	115	32566	9
ORANGE	CAPSTRNO	SANDIEGO	138	22112	15
ORANGE	LAGNA NL	SANDIEGO	138	22396	15
ORANGE	MARGARTA	SANDIEGO	138	22432	15
ORANGE	PICO	SANDIEGO	138	22656	15
ORANGE	TRABUCO	SANDIEGO	138	22860	15
PLACER	ROLLINS	PG AND E	60	32378	8
PLACER	PENRYN	PG AND E	60	32270	3
RIVERSIDE	VALLEYSC	SOCALIF	115	24160	7
RIVERSIDE	MIRAGE	SOCALIF	115	24807	7
RIVERSIDE	BANNING	SOCALIF	115	24814	7
RIVERSIDE	GARNET	SOCALIF	115	24815	7
RIVERSIDE	SANTA RO	SOCALIF	115	24816	7
RIVERSIDE	EISENHOW	SOCALIF	115	24817	7
RIVERSIDE	FARREL	SOCALIF	115	24818	7
SACRAMENTO	GOLD HLL	PG AND E	60	32110	5
SACRAMENTO	ALMOND	PG AND E	69	38492	5
SACRAMENTO	GRAND IS	PG AND E	115	31994	5
SACRAMENTO	BRIGHTN	PG AND E	115	31984	5
SACRAMENTO	SOUTHCTY	PG AND E	115	37057	5
SACRAMENTO	MID CTY	PG AND E	115	37055	5

SACRAMENTO	HEDGE	PG AND E	115	37053	5
SACRAMENTO	ELVERTAS	PG AND E	115	37052	5
SAN BERNARDINO	CHINO	SOCALIF	66	24024	5
SAN BERNARDINO	AMERON	SOCALIF	66	24032	5
SAN BERNARDINO	PADUA	SOCALIF	66	24111	5
SAN BERNARDINO	VSTA	SOCALIF	66	24902	5
SAN BERNARDINO	YUCCA	SOCALIF	115	24809	5
SAN BERNARDINO	HI DESER	SOCALIF	115	24810	5
SAN DIEGO	DIVISION	SANDIEGO	69	22172	8
SAN DIEGO	MAIN ST	SANDIEGO	69	22420	8
SAN DIEGO	MELROSE	SANDIEGO	69	22440	8
SAN DIEGO	NATNLCTY	SANDIEGO	69	22548	8
SAN DIEGO	SAMPSON	SANDIEGO	69	22700	8
SAN DIEGO	TALEGA	SANDIEGO	69	22836	8
SAN DIEGO	URBAN	SANDIEGO	69	22868	8
SAN FRANCISCO	MISSON	PG AND E	115	33203	5
SAN JOAQUIN	OAK PARK	PG AND E	60	33680	8
SAN JOAQUIN	LINDEN	PG AND E	60	33642	8
SAN JOAQUIN	LODI	PG AND E	60	33728	8
SAN JOAQUIN	TERMNOUS	PG AND E	60	33720	8
SAN JOAQUIN	METTLER	PG AND E	60	33718	8
SAN JOAQUIN	HAMMER	PG AND E	60	33714	8
SAN JOAQUIN	WESTLANE	PG AND E	60	33712	8
SAN JOAQUIN	E.STCKTN	PG AND E	60	33676	8
SAN JOAQUIN	FRNCH CP	PG AND E	60	33698	8
SAN JOAQUIN	MONARCH	PG AND E	60	33678	8
SAN LUIS OBISPO	TEMPLETN	PG AND E	230	30905	5
SAN MATEO	BURLNGME	PG AND E	60	33356	10
SANTA CLARA	STANFORD	PG AND E	60	33386	10
SANTA CLARA	LOS ALTS	PG AND E	60	35450	10
SANTA CLARA	CLY LNDG	PG AND E	115	33316	10

SANTA CLARA	AMES DST	PG AND E	115	35349	10
SANTA CLARA	PLO ALTO	PG AND E	115	38028	10
SANTA CRUZ	LONESTAR	PG AND E	115	33320	5
SOLANO	UCDAVSJ1	PG AND E	60	32116	5
SOLANO	DIXONCAN	PG AND E	60	32106	5
SOLANO	UCDAVSJ2	PG AND E	60	32103	5
SOLANO	DIXON LD	PG AND E	115	35600	5
STANISLAUS	INDUSTRL	PG AND E	60	38060	5
STANISLAUS	FINNEY	PG AND E	69	38254	5
STANISLAUS	STANDFRD	PG AND E	69	38252	5
STANISLAUS	PARKER	PG AND E	69	38250	5
STANISLAUS	PRESCOTT	PG AND E	69	38260	5
STANISLAUS	F STREET	PG AND E	69	38474	5
SUTTER	TUDOR	PG AND E	60	32340	5
SUTTER	E.NICOLS	PG AND E	60	32342	5
SUTTER	CATLETT	PG AND E	60	32306	5
SUTTER	CATLETJT	PG AND E	60	32305	5
SUTTER	YUBACITY	PG AND E	60	32302	5
SUTTER	PEASE	PG AND E	60	32332	5
SUTTER	BARRY	PG AND E	60	32338	5
SUTTER	PEASETP	PG AND E	60	32333	5
VENTURA	MANDALAY	SOCALIF	66	24223	15
VENTURA	MANDALAY	SOCALIF	66	24223	7
YOLO	DAVIS	PG AND E	60	32104	5
YOLO	WOODLD	PG AND E	115	31970	5
YOLO	DAVIS	PG AND E	115	31990	5
YOLO	DEEPWATR	PG AND E	115	31988	5
YOLO	W.SCRMNO	PG AND E	115	31986	5
YOLO	DPWTR_TP	PG AND E	115	31980	5
YUBA	WHEATLND	PG AND E	60	32350	4
YUBA	PLUMAS	PG AND E	60	32344	4

YUBA	YUBAGOLD	PG AND E	60	32316	4
YUBA	DOBBINS	PG AND E	60	31660	4
YUBA	OLIVHRST	PG AND E	115	32204	4
Total					952

Several power flow simulations were completed. A power flow of the 2017 summer peak base case was completed as a benchmark of the current status of the California transmission system. This base case simulation produces a base AMWCO (Aggregated Megawatt Contingency Overload) value which would be used to compare to the biomass alternatives. Table 37 shows the results of the 2017 summer base case.

Table 37. 2017 Summer Base Case Results[100]

2017 Summer Base Case	
Contingencies:	735
Violations:	1115
AMWCO:	28,045 MW

Table 38 shows the results of having 952 MW of biomass installed in 31 counties. The total number of counties was slightly smaller than the 39 initially listed. Some of the counties did not have transmission hot spots or were too small to consider.

Table 38. 2017 Summer Biomass Case Results for 952 MW[101]

2017 Summer Case /w 952 MW	
Contingencies:	489
Violations:	759
AMWCO:	23,975 MW
AMWCO Impact:	- 4,070 MW
Benefit Ratio:	- 4.47

The addition of 952 MW into the system at these locations proved to be very beneficial. The benefit ratio was -4.47 MW. Signifying that for every 1 MW of biomass installed there is a reduction of total overloads by 4.47 MW.

Economic Analysis of Landfill Gas, Dairy Manure, Wastewater Treatment, and Urban Fuels

The results of the economic analysis for 2010 and 2017 timeframe using landfill gas, dairy manure and wastewater treatment facilities are shown below:

Table 39. 2010 LCOEs in Current $ (228 MW total)[102]

Biomass Resource	Capacity (MW)	Transmission Impact ratio	2010 No PTC	2010 with PTC	Wholesale Price CEC 2003 forecast for 2010	Wholesale Price E3 - CPUC Forecast for 2010*	Market Price Referents	LCOE Combined cycle for 2010*
Dairy Manure* (200 kW)	21	-4.54	0 .0419	0.0376	0.0426	0.06304	0.0605	0.07419
Landfill Gas (1 MW)	162	-4.54	0.0366	0.0323	0.0426	0.06304	0.0605	0.07419
Waste water (1MW)	45	-4.54	0.0463	0.0419	0.0426	0.06304	0.0605	0.07419

* Assumed sales of sludge/fertilizer

Table 40. 2017 LCOEs in Current $ (952 MW total)[103]

Biomass Resource	Capacity (MW)	Transmission Impact ratio	2017 No PTC	2017with PTC	Wholesale Price CEC 2003 forecast for 2017	Wholesale Price E3 - CPUC Forecast for 2017*	Market Price Referents	LCOE Combined cycle for 2017*
Dairy Manure* (200 kW)	37	-4.47	0.0257	0.0214	0.0587	0.07164	0.0605	0.09152
Landfill Gas (1 MW)	499	-4.47	0.0342	0.0298	0.0587	0.07164	0.0605	0.09152
Waste water (1MW)	58	-4.47	0.0423	0.0379	0.0587	0.07164	0.0605	0.09152
Urban Fuels (25 MW)	361	-4.47	0.0423	0.0645	0.0602	0.07164	0.0605	0.09152

* Assumed sales of sludge/fertilizer

As shown in Table 39, it is economically viable to develop 228 MW of landfill gas, dairy waste and wastewater to energy facilities by 2010 using all the criteria for comparison (in current dollar analysis). Similarly, by 2017 it is also economically cost competitive to install 952 MW of landfill gas, dairy waste, wastewater, and urban fuels to energy facilities (Table 40).

In summary, the strategic value analysis conducted by the Energy Commission staff in conjunction with DPC team, CDF, California Biomass Collaborative, and McNeil Technologies the economic potential of biomass that can be developed using current dollar analysis are:

2010 using forest fuels:

Zero megawatt using CEC 2003 wholesale price forecast comparison.

59 MW in Humboldt County using E3 CPUC wholesale price forecast comparison.

181 MW (59 MW in Humboldt County+ 43 MW in Trinity County + 39 MW in Shasta County + 40 MW in Nevada County) using LCOE of combined cycle comparison.

Zero megawatt using MPR comparison.

2010 using landfill gas, dairy, and wastewater:

A total of 228 MW using all criteria of comparison (21 MW dairy, 45 MW waste water, and 162 MW landfill gas).

2017 using forest fuels:

59 MW in Humboldt County using CEC 2003 wholesale price forecast comparison.

248 MW (59 MW in Humboldt County + 43 MW in Trinity County + 35 MW in Mendocino County + 39 MW in Shasta County + 32 MW in Plumas County + 40 MW in Nevada) using E3 CPUC wholesale price forecast comparison.

382 MW (all identified sites except 11 MW in Tehama County) using LCOE of combined cycle comparison

59 MW in Humboldt County using MPR comparison.

2017 using landfill gas, dairy, wastewater and urban fuels

A total of 952 MW using LCOE of combined cycle comparison (37 MW dairy, 58 MW wastewater, 499 MW landfill gas, and 361 MW Urban fuels).

The results of this biomass SVA analysis are also being reported in the renewable integration study prepared by DPC team.[104] Based from the analysis, development of biomass energy conversion systems will for this reason occur over a wide capacity

range from a few kilowatts to the multi-megawatt depending on location, resource availability, transportation and other infrastructure, conversion process, regulatory conditions, product, and market. Biofuels and bioproducts manufacturing which was not evaluated in the analysis may likewise be developed over a wide range of sizes and capacity.

Thus, using the strategic value methodology an incremental capacity growth of up to 228 MW from biomass may be installed by 2010. And by 2017, an incremental capacity of up to 1,334 MW from biomass may be developed.

Benefits of Biomass Resources Development

Sustainable biomass utilization offers multiple benefits, including:

Renewable energy: Biomass energy conversion reduces demand for fossil fuels, including imports, and increases security and reliability of supply.

Local air quality benefits: Biomass conversion results in reductions in emissions of criteria and hazardous air pollutants in comparison with open burning and wildfires. It also reduces emissions of volatile organic compounds, odors, dust, and nuisances associated with agricultural operations such as dairies and animal feeding operations.

Water quality benefits: Proper management of fuel stocks in forests to reduce catastrophic wildfires can reduce post-fire soil erosion and hydrologic and water-shed impacts. Improved management of animal manure and solid wastes controls nutrient loadings and reduces ground water contamination. Digestion of food processing and other waste-waters reduces organic loadings for land application or further treatment by municipal systems.

Global climate change impacts: Biomass utilization reduces net carbon emissions to the atmosphere and provides reductions in methane emissions from natural decay processes. Increasing production of biomass can sequester atmospheric carbon over the short to medium term, and promote carbon sequestration in soils.

Ecosystem impacts: Decreased intensity of wildfires reduces tree mortality and loss of wildlife habitat.

Jobs: Biomass utilization leads to primary jobs creation in collection, construction, and facility operations, and secondary jobs through local and regional economic impacts. These jobs would be created in both rural and urban areas as greater use is made of all types of biomass in the state.

Local economic development: Biomass development yields tax benefits and creates additional economic activity to help revitalize many communities, especially in rural and agricultural areas with high unemployment.

New agricultural markets: Biomass can be used for a wide range of bio-products, providing new opportunities for agriculture.

Reduced economic losses from wildfires: Managing fuel loads in forests to reduce the intensity of wildfire decreases losses from wildfires. Currently 2.2 million acres in the state are at extreme risk of wildfire, 15 million acres are at very high risk. Total annual economic losses from wildfire exceed $160 million. Wildfire suppression costs annually exceed $900 million.

Reduced waste disposal: Using waste for energy and products reduces disposal in landfills.

Land use impacts and soil reclamation: Biomass production can contribute to soil and land reclamation through phytoremediation. Biomass crops can reduce drainage water impacts and help manage salts on irrigated lands while producing fuels and value-added products. More than 1.5 million acres of farm land are drainage-impaired in the San Joaquin Valley alone.

Local grid support: Distributed and strategically located biomass power systems, like other distributed systems, can provide local voltage support and reduce electricity transmission requirements, helping to mitigate congestion during periods of high power demand.

Flexibility in power generation: Biomass power plants can operate as base-load and in some cases as peaking facilities, providing flexibility in electricity system management and complementing generation from intermittent resources such as wind and solar.

On-site power generation: Biomass fuels can also be used at the site of generation, such as at sawmills, dairies, and food processing operations. On-site power generation, often coupled with heat utilization, serves to displace retail purchases for power and fuel, reducing demand for grid power and natural gas, and reducing costs of energy for the facility.

Table 41 highlights economic benefits associated with altering management of agricultural and forestry residues.

Table 41. Economic Benefits of biomass utilization[105]

Benefit	Amount	Beneficiaries
Open burn emission reduction value	$15,395,196	California residents Local air districts
Wildfire emission reduction value	$2,020,275	California residents Local air districts
Landfill capacity extension value	$20,624,300	Landfill owners Waste Mgmt Board California Residents
Wildfire risk reduction value	$23,291,405	Local property owners USFS/CDF California residents
Forest health improvement value	$560,000	Local property owners
Alternative agricultural disposal value	$21,824,964	Agricultural producers

Projected benefits associated with biomass development are presented in Table 42. Environmental benefits associated with new capacity additions are derived from comparison of emissions from a combined cycle natural gas-fired power plant with a representative biomass power plant. The values shown in Table are for both 2010 and 2017. In 2010, California biomass plants are projected to generate nearly 1.8 GWh of electricity and associated generation will displace over 1.2 million tons of CO_2 and a nominal amount of SO_x. By 2017 installed capacity is projected to increase to 1,356 MW with concurrent reductions in CO_2 and SO_x emissions.

Table 42. Environmental Benefits Associated with Biomass Development[106]

	2010		2017		
Category	Forestry	Biogas	Forestry	Biogas & Urban	Total
Capacity (MW)	0	228	382	724	1,334
Capacity Factor	85%	90%	85%	90%	
Generation (GWh)	0	1,799	2,928	5,799	10,526
Avoided Emissions (tonnes/year)					
CO2	0	1,272,348	2,071,286	2,872,319	6,215,953
NOx	0.0	0.0	0.0	0.0	0.0
SOx	0.0	14.3	23.3	14.3	52.0
CO	0.0	0.0	0.0	0.0	0.0
TOG	0.0	0.0	0.0	0.0	0.0
ROG	0.0	0.0	0.0	0.0	0.0
PM	0.0	0.0	0.0	0.0	0.0
PM 10	0.0	0.0	0.0	0.0	0.0

Forecasts for additional biomass capacity installations in 2010 and 2017 have associated economic impacts. As presented in Table 44, increases in employment and taxes are projected to be on the order of 6,000 new jobs and over $22.9 million in tax revenues. Most of the jobs are associated with construction of the facilities and thus do not represent long-term employment.

Table 43. Projected Economic Impacts Associated with Biomass Development[107]

| | 2010 | | 2017 | | |
	Forestry	Biogas	Forestry	Biogas & Urban	Total
Category					
Employment (#)	0	520	2,285	3,558	6,362
Taxes ($Million)	$ -	$ 3.6	$ 7.2	$ 11.6	$ 22.4
Emis. Ben. ($Million)	$ -	$ 0.1	$ 0.2	$ 0.1	$ 0.5
Total Benefits ($Million)	$ -	$ 3.7	$ 7.4	$ 11.8	$ 22.9

Out-of-State Prospects

While many WECC states have since developed their own renewable energy targets to serve native load, the renewable resource in most of the states continues to far exceed the potential indigenous demand. In fact, many of these states have begun developing energy infrastructure development strategies that target California export markets as a key opportunity.

Estimates of renewable energy technical potential are approximations of the amount of energy that could technically be generated from each resource type, based on a current set of data on resource availability and assumptions about generation technologies. It is important to note that these estimates ignore the obstacles of getting that supply to market (e.g., transmission constraints), as well as certain siting and permitting issues. Furthermore, future technology improvements or regulatory constraints (e.g., new permitting restrictions) could significantly alter future estimates of gross technical potential. Not all of the technical potential, or even a significant fraction of it, is likely to be realized.

Table 44. Biomass Energy Technical Potential (GW)

Western US outside of California[108]
(Biomass)

State	Biomass
Arizona	0.14
Colorado	0.6
Idaho	1.3
MT	0.9
New Mexico	0.1
NV	0.1
OR	1.4
UT	0.1
WA	1.6
WY	-

Summary

Biomass energy development provides environmental, social, and economic benefits far in excess of current practices. There is a need for coordinated efforts to change management and regulatory philosophies to better reflect the value of biomass as a renewable resource. California biomass is prevalent, widespread and diverse. The current capacity across all generating types is close to 1,000 Megawatts (MW$_e$). Using the strategic value analysis methodology an incremental addition of up to 1,334 MW can be economically developed by 2017. With the RPS mandate and the availability of PTC and other incentives, biomass energy development can increase substantially.

[1] Energy Commission, http://www.energy.ca.gov

[2] http://biomass.ucdavis.edu/pages/assessment.html and also presented at the IEPR workshop on May 9, 2005

[3] ftp://frap.cdf.ca.gov/pub/outgoing/biomass/

[4] nominally zero moisture content. 1 BDT = 2,000 lbs = 0.907 metric tons or 0.907 Mg (Megagram = 1,000 kg).

[5] Reserves include wild and scenic river areas, wilderness areas, USDA Forest Service special interest areas and research natural areas, private reserves, state parks, BLM reserves, national parks, and Dept of Fish and Game and US Fish and Wildlife Service game preserves

[6] The section 45 tax credits (PTC) were extended when HR 4520 (American Jobs Creation Act) was enacted on 22 October 2004. Geothermal, solar, wind, and closed loop biomass are eligible for the 1.5 cents/kWh credit indexed for inflation (now at 1.8 cents/kWh).

[7] In http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/index.html and http://biomass.ucdavis.edu/pages/reports/BiomassPotentials.html The base case capital cost for 2005 includes cost of emission control technologies that may meet the California Air Resources Board standards. Breakdown of costs were estimated consistent with EPRI-TAG RE 2002 and EPRI-TAG RE 2004. EPA cost calculator for Selective Catalytic Reduction (SCR) is between $100-$300/kW for NOx emissions.

[8] Ibid, in references http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/index.html and http://biomass.ucdavis.edu/pages/reports/BiomassPotentials.html. Breakdown of costs were estimated consistent with EPRI-TAG RE 2002 and EPRI-TAG RE 2004.

[9] Renewable Energy Technical Assessment Guide. EPRI TAG-RE 2002 and EPRI TAG-RE 2004. EPRI, Palo Alto, CA

[10] Ibid, in references EPRI TAG-RE 2002 and EPRI TAG-RE 2004.

[11] Personal Communication with J.G. Patel, Carbona Corporation. January 2005.

[12] Ibid, Patel 2005. Breakdown of cost for gasification system were derived from http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/index.html.

[13] http://www.energy.ca.gov/reports/2002-04-08_500-02-020F.PDF. Economic and financial Aspects of Landfill gas to Energy Project Development in California and http://www.energy.ca.gov/reports/2002-09-09_500-02-041V1.PDF. Landfill Gas to Energy Potential in California.

[14] Draft Biomethane from Dairy Waste Report. A sourcebook for the production and use of renewable natural gas in California, June 6, 2005.

[15] Ibid, Draft Biomethane from Dairy Waste Report. 2005. Breakdown of cost is derived from http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/index.html

[16] Electricity Infrastructure Assessment Report, May 2003 pp 15-19. For 2003 CEC wholesale price forecast

[17] The bone dry ton is a standard industry designation for a ton of material at nominal zero moisture content.

[18] An earlier assessment for 2003 estimated 71 million gross and 26 million technically available BDT/y, see California Biomass Collaborative, 2004, An assessment of biomass resources in California, PIER Consultant Report, California Energy Commission, Sacramento, CA, http://biomass.ucdavis.edu. The current values are based on a 2005 update including a reassessment of forest resources by the California Department of Forestry and Fire Protection along with increases in municipal solid waste generation.

[19] http://biomass.ucdavis.edu/pages/reports/BiomassPotentials.html

[20] California Climate Action Registry Forest Protocols Overview, 2004, http://www.climateregistry.org/docs/PROTOCOLS/Forestry/04.06.14_Final_Forest_Protocols_Board_Overview.pdf

[21] Summary for Policy Makers, a report of Working Group I of the Intergovernmental Panel on Climate Change, 2001, http://www.ipcc.ch/pub/spm22-01.pdf

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[24] CIWMB, 2002, Remaining landfill capacity in California, http://www.ciwmb.ca.gov/agendas/mtgdocs/2002/02/00007306.doc

[25] http://www.ciwmb.ca.gov/Organics/Conversion/

[26] http://www.ciwmb.ca.gov/LGCentral/Rates/Diversion/RateTable.htm

[27] The value of 598,000 tons per year given in the California Fire Plan (California Fire Plan, 2004, http://www.fire.ca.gov/FireEmergencyResponse/FirePlan/appendixc_part1.html) has been updated by the California Air Resources Board.

[28] California Air Resources Board Emissions Inventory, 2004, http://www.arb.ca.gov/app/emsinv/emssumcat_query.php?F_YR=2004&F_DIV=0&F_SEASON=A&SP=2005&F_AREA=CA#9

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[31] Green-e renewable electricity certification program, http://www.green-e.org/ipp/standard_for_marketers.html

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[41] Additional information is available through hte US EPA AgStar program, http://www.epa.gov/agstar/index.html, the California Energy Commission, http://www.energy.ca.gov/index.html, and Western United Resource Development, Inc., http://www.wurdco.com/

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transmission charges and other surcharges, so no value is currently ascribed to the local or distributed generation aspect that may reduce overall utility transmission requirements. Additionally, excess energy in the year is retained by the utility without compensating the customer-generator. Recently introduced legislation (AB 728, 2005) would extend biogas net metering indefinitely, increase the generator size limit to 10 MWe, and eliminate the capacity caps. The compensation structure is unaltered, and the bill remains restricted to biogas digester systems.

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[80] Ibid, Davis Power Consultants, March 8, 2005

[81] Ibid, Davis Power Consultants, March 8, 2005

[82] Ibid, Davis Power Consultants, March 8, 2005

[83] Ibid, Davis Power Consultants, March 8, 2005

[84] Ibid, Davis Power Consultants, March 8, 2005

[85] Ibid, Davis Power Consultants, March 8, 2005

[86] Ibid, Davis Power Consultants, March 8, 2005

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